MONTANA LEGISLATIVE HISTORY

Chapter 491 ~~19~~ 2007

Bill H 25 S _____ Original bill & history ___C

H. Committee on Fed Rel, Energy & Tel

Hearing Date(s) 1/24 ___C
2/13 ___C
_____ ___C
_____ ___C

Date Out _____ ___C

S. Committee on Nat. Res & Energy

Hearing Date(s) 3/30 ___C
4/02 ___C
_____ ___C
_____ ___C

Did this bill originate in an interim committee? ___Yes ___No

Committee _____ Report _____

Conference Committee
hearing 4/16
report 4/17

Montana Legislative Branch

Montana Legislature

Detailed Bill Information

2007 Session

| Top | Actions | Sponsor, etc. | Subjects | Add'l Bill Info | Eff. Dates | New Search |

Bill Draft Number: LC0170 Current Bill Text: HTML PDF (w/line numbers) NEW
Bill Type - Number: HB 25 Fiscal Note
Short Title: Generally revise electric industry restructuring laws
Primary Sponsor: Alan Olson
Chapter Number: 491

Bill Actions - Current Bill Progress: Became Law

Bill Action Count: 75

Print Friendly

Action - Most Recent First	Date	Votes Yes	Votes No	Committee
Chapter Number Assigned	05/15/2007			
(H) Signed by Governor	05/14/2007			
(H) Transmitted to Governor	05/04/2007			
(S) Signed by President	05/04/2007			
(H) Signed by Speaker	05/02/2007			
(H) Returned from Enrolling	04/23/2007			
(C) Sent to Printing	04/21/2007			
(H) Sent to Enrolling	04/19/2007			
(S) 3rd Reading Conference Committee Report Adopted	04/19/2007	29	21	
(H) 3rd Reading Conference Committee Report Adopted	04/19/2007	60	40	
(S) Scheduled for 3rd Reading	04/19/2007			
(H) Scheduled for 3rd Reading	04/19/2007			
(S) 2nd Reading Conference Committee Report Adopted	04/18/2007	29	21	
(S) 2nd Reading Conference Committee Report Rejected Motion Failed	04/18/2007	22	28	

(H) 2nd Reading Conference Committee Report Adopted	04/18/2007	71	29	
(H) Scheduled for 2nd Reading	04/18/2007			
(S) Scheduled for 2nd Reading	04/18/2007			
(S) Conference Committee Report Received	04/17/2007			
(H) Conference Committee Report Received	04/17/2007			
(S) Hearing	04/16/2007			(S) Conference
(S) Conference Committee Appointed	04/16/2007			
(H) Conference Committee Appointed	04/14/2007			
(H) Conference Committee Dissolved	04/14/2007			
(H) Conference Committee Appointed	04/13/2007			
(H) Motion Failed	04/11/2007	48	50	
(H) 2nd Reading Senate Amendments Concur Motion Failed	04/10/2007	46	54	
(H) Scheduled for 2nd Reading	04/10/2007			
(S) Returned to House with Amendments	04/05/2007			
(S) 3rd Reading Concurred	04/05/2007	30	20	
(C) Sent to Printing	04/05/2007			
(S) Scheduled for 3rd Reading	04/05/2007			
(S) 2nd Reading Concurred as Amended	04/04/2007	28	22	
(S) 2nd Reading Concur as Amended Motion Failed	04/04/2007	25	25	
(S) 2nd Reading Motion to Amend Carried	04/04/2007	34	16	
(S) 2nd Reading Motion to Amend Carried on Voice Vote	04/04/2007	50	0	
(S) Scheduled for 2nd Reading	04/04/2007			
(S) Scheduled for 2nd Reading	04/04/2007			
(C) Sent to Printing	04/02/2007			
(S) Committee Report--Bill Concurred as Amended	04/02/2007			(S) Natural Resources and Energy
(S) Committee Executive Action--Bill Concurred as Amended	04/02/2007	5	4	(S) Natural Resources and Energy
(S) Hearing	03/30/2007			(S) Natural Resources and Energy
(S) Referred to Committee	03/17/2007			(S) Natural Resources and Energy

(S) First Reading	03/17/2007			
(H) Transmitted to Senate	02/15/2007			
(H) 3rd Reading Passed	02/15/2007	69	30	
(H) Scheduled for 3rd Reading	02/15/2007			
(H) 2nd Reading Passed	02/14/2007	69	31	
(H) 2nd Reading Motion to Amend Failed	02/14/2007	35	65	
(H) 2nd Reading Motion to Amend Failed	02/14/2007	31	69	
(H) Scheduled for 2nd Reading	02/14/2007			
(C) Sent to Printing	02/13/2007			
(H) Committee Report--Bill Passed as Amended	02/13/2007			(H) Federal Relations, Energy, and Telecommunications
(H) Committee Executive Action--Bill Passed as Amended	02/13/2007	8	4	(H) Federal Relations, Energy, and Telecommunications
(H) Sponsor List Modified	01/25/2007			
(H) Hearing	01/24/2007			(H) Federal Relations, Energy, and Telecommunications
(H) Fiscal Note Printed	01/04/2007			
(H) First Reading	01/03/2007			
(H) Fiscal Note Received	12/26/2006			
(H) Referred to Committee	12/20/2006			(H) Federal Relations, Energy, and Telecommunications
(H) Fiscal Note Requested	12/12/2006			
(C) Introduced Bill Text Available Electronically	11/27/2006			
(H) Introduced	11/27/2006			
(C) Pre-Introduction Letter Sent	11/13/2006			
(C) Draft in Assembly/Executive Director Review	11/09/2006			
(C) Draft in Input/Proofing	11/09/2006			
(C) Draft to Drafter - Edit Review [CAJ]	11/09/2006			
(C) Draft in Edit	11/09/2006			
(C) Draft in Final Drafter Review	11/08/2006			
(C) Bill Draft Text Available Electronically	10/31/2006			
(C) Draft in Input/Proofing	10/31/2006			
(C) Draft to Drafter - Edit Review [CAJ]	10/30/2006			
(C) Draft in Edit	10/30/2006			

(C) Draft in Legal Review	10/27/2006			
(C) Draft to Requester for Review	10/27/2006			
(C) Draft Request Received	06/22/2006			

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Sponsor, etc.

Sponsor, etc.	Last Name/Organization	First Name	Mi
Requester	Energy and Telecommunications Interim Committee		
Drafter	Everts	Todd	
By Request Of	Energy and Telecommunications Interim Committee		
Primary Sponsor	Olson	Alan	

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Subjects

Description	Revenue/Approp.	Vote Majority Req.	Subject Code
Energy		Simple	ENER
Trade Regulations and Competition		Simple	TRAD

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Additional Bill Information

Probable Fiscal Note: Yes
Preintroduction Required: Y
Session Law Ch. Number: 491
DEADLINE
Category: General Bills
Transmittal Date: 02/28/2007
Return (with 2nd house amendments) Date: 04/05/2007

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Section Effective Dates

Section(s)	Effective Date	Date Qualified
All Sections	01-OCT-07	

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06/03/2011 09:53 AM Mountain Time
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Senate Agenda(s)	Senate Journals	Daily Senate Floor Actions
Legislator Information	Reports

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GOVERNOR'S OFFICE OF BUDGET AND PROGRAM PLANNING

Fiscal Note – 2009 Biennium

Bill #	HB0025	Title:	Generally revise electric industry restructuring laws
Primary Sponsor:	Olson, A.	Status:	As Introduced

☐ Significant Local Gov Impact ☐ Include in HB 2 ☐ Technical Concerns

☐ Included in the Executive Budget ☐ Significant Long-Term Impacts ☐ Dedicated Revenue Form Attached

FISCAL SUMMARY

Description of Fiscal Impact:

	FY 2008 Difference	FY 2009 Difference	FY 2010 Difference	FY 2011 Difference
Expenditures:				
General Fund	$0	$0	$0	$0
Revenue:				
General Fund	$0	$0	$0	$0
Net Impact-General Fund Balance:	$0	$0	$0	$0

FISCAL ANALYSIS

Assumptions:

1. This bill has no fiscal impact to the state

Sponsor's Initials	*Date*	*Budget Director's Initials*	*Date*

MINUTES

MONTANA HOUSE OF REPRESENTATIVES
60th LEGISLATURE - REGULAR SESSION

COMMITTEE ON FEDERAL RELATIONS, ENERGY, AND TELECOMMUNICATIONS

Call to Order: By **CHAIRMAN ALAN OLSON**, on January 24, 2007 at 3:00 P.M., in Room 172 Capitol.

ROLL CALL

Members Present:

Rep. Alan Olson, Chairman (R)
Rep. George G. Groesbeck, Vice Chairman (D)
Rep. Harry Klock, Vice Chairman (R)
Rep. Scott Boggio (R)
Rep. Robyn Driscoll (D)
Rep. Dave Gallik (D)
Rep. Dennis Himmelberger (R)
Rep. Llew Jones (R)
Rep. Diane Rice (R)
Rep. Wayne Stahl (R)
Rep. Bill Thomas (D)
Rep. Jonathan Windy Boy (D)

Members Excused: None.

Members Absent: None.

Staff Present: Todd Everts, Legislative Branch
Cindy Peterson, Committee Secretary

Audio Committees: These minutes are in outline form only. They provide a list of participants and a record of official action taken by the committee. The link to the audio recording of the meeting is available on the Legislative Branch website.

Committee Business Summary:

Hearing & Date Posted: HJ 6, 1/15/2007; HB 301, 1/15/2007; HB 330, 1/17/2007; HB 25, 1/17/2007
Executive Action: None.

02:12:54 Cedion Jones, Montanans for Corporate Accountability
02:14:46 Derf Johnson, Montana Public Interest Research Group

Opponents' Testimony:

02:15:23 Doug Hardy, Montana Electric Cooperatives Association
EXHIBIT(feh16a14)
02:17:35 Donald Quander, representing himself
02:24:51 John Fitzpatrick, Northwestern Energy
02:26:43 Don Allen, Western Environmental Trade Association

Informational Testimony: None

Questions from Committee Members and Responses: None

Closing by Sponsor:

02:28:58 Rep. Reinhart

HEARING ON HB 25

Opening Statement by Sponsor:

02:33:58 Rep. Alan Olson (R), HD 45, opened the hearing on HB 25, generally revise electric industry restructuring laws.

Proponents' Testimony:

02:37:29 John Fitzpatrick, Northwestern Energy
EXHIBIT(feh16a15)
02:46:06 Russ Doty, Green Electricity Buying Cooperative

Opponents' Testimony:

02:49:54 Doug Mood, Vice Chairman, PSC
EXHIBIT(feh16a16)
02:55:41 David Hoffman, PPL Montana
03:02:08 Colleen Balzarini, City of Great Falls
EXHIBIT(feh16a17)
03:05:37 Steve North, Great Falls Development Authority
03:07:10 Jeff Mangan, Great Falls International Airport Authority
EXHIBIT(feh16a18)
03:09:44 Bob Nelson, Montana Consumer Counsel

Informational Testimony:

03:14:14 Don Quander, Montana Large Customer Group
03:18:47 John Alke, Montana Dakota Utilities

Questions from Committee Members and Responses:

03:20:03 Rep. Jones
03:24:52 Mr. Mood

Closing by Sponsor:

03:25:16 Rep. Olson

Additional Exhibits:

EXHIBIT(feh16a19)
EXHIBIT(feh16a20)
EXHIBIT(feh16a21)
EXHIBIT(feh16a22)
EXHIBIT(feh16a23)

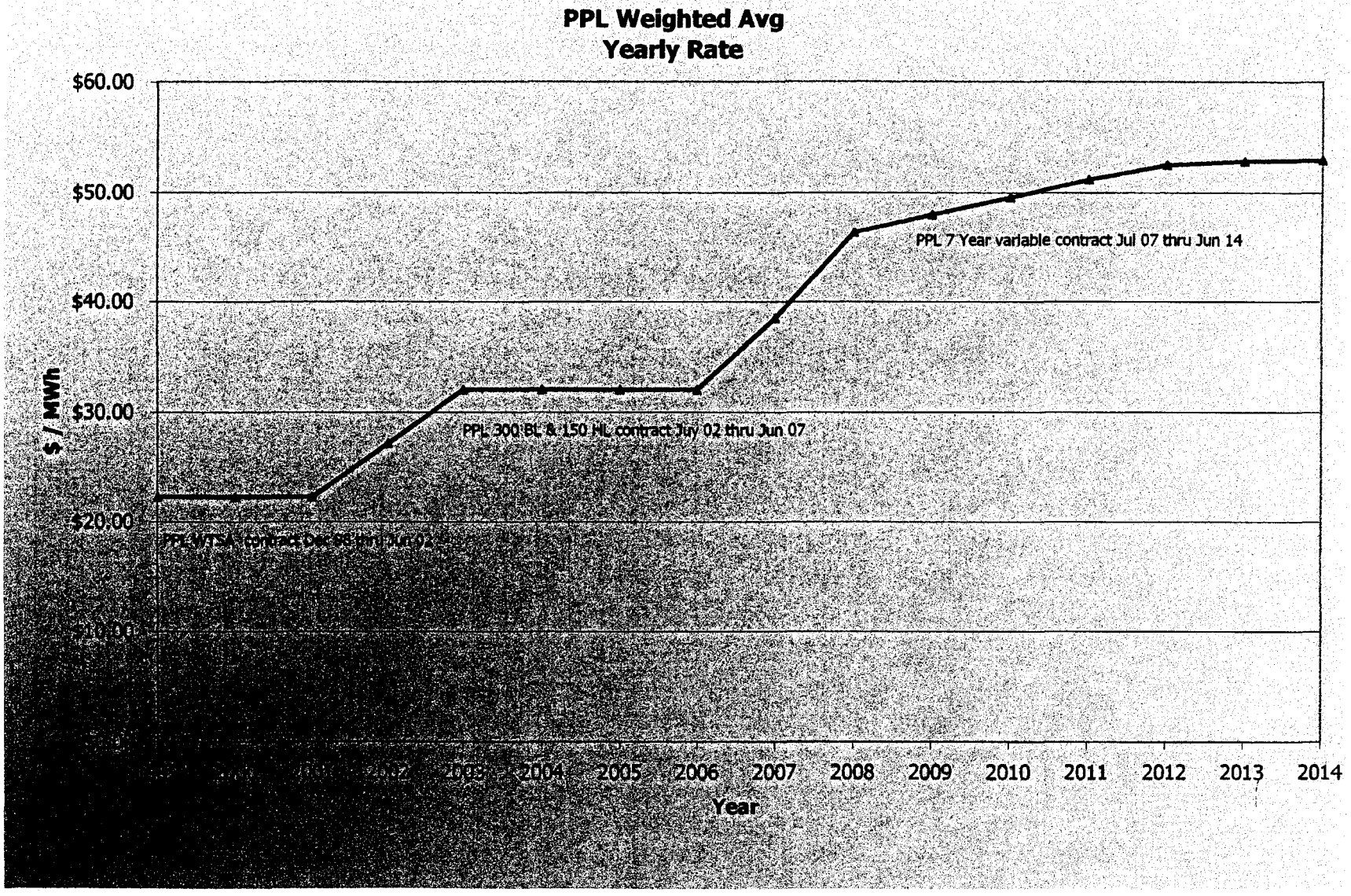


EXHIBIT 15
DATE 1-24-07
HB 25

EXHIBIT 16
DATE 1-24-07
HB 25

TESTIMONY IN OPPOSITION TO HB 25
GENERALLY REVISE ELECTRIC RESTRUCTURING LAWS

Doug Mood
Vice-Chairman, Montana PSC
January 24, 2007

Mr. Chairman and Members of the Committee,

The Public Service Commission, by a 3-2 margin, has voted to oppose HB 25. But I want to make this next point entirely clear. The Commission is strongly in favor of broad reform of Title 69, Chapter 8. We believe that this legislative session should provide the framework for transitioning NorthWestern Energy from its current status as Montana's sole restructured utility and default electricity supplier, back to an integrated service utility that owns rate-based generation and is traditionally regulated by the PSC. However, HB 25 in its current form is not acceptable to the PSC.

HB 25 retains too much of Chapter 8 and amends it in ways that are neither necessary nor helpful --- if the objective is to move toward a traditional, regulated utility model. The PSC recommends making numerous substantive amendments to HB 25.

One of the PSC's major objections to this bill involves the definitions in Section 6 of "electricity supply costs," "electricity supply service," and "new electricity supply resource." Those definitions, in combination with Section 8 (of the bill), subsection (1), would establish bad and unworkable public policy. This subsection requires the PSC to flow NorthWestern's electricity generation supply costs through a "tracker."

A reasonable argument can be made for allowing a utility to recover certain volatile fuel costs and market based power purchase costs through a monthly tracker. However, it is neither reasonable nor efficient to require tracking of those costs relative to utility-owned generation. The tracker requirement for electricity supply costs would basically require NorthWestern to file the equivalent of a general rate case at the PSC at least once a year. The Commission sees the approval process provided for in 69-8-420 as determining recoverable costs for utility owned

generation for the life of the generation plant. Changes would only occur if the utility could establish to the Commission's satisfaction that extraordinary circumstances warrant a change.

Some of the PSC's other concerns with HB 25 include:

- In Section 12, the requirement that the PSC act on pre-approval requests for generation ownership or lease within 180 days does not provide sufficient time to adequately consider and act on these complex and critically important applications.

- HB 25 fails to eliminate some of the unnecessary provisions and definitions in the current Chapter 8 to more fully accomplish the abandonment of the functionally separate, default supplier statutory framework under which NorthWestern currently operates;

- The electricity supply planning provisions in Section 10 could and should be repealed in favor of the existing integrated resource planning provisions in Chapter 3, Part 12. Those provisions currently apply to MDU and used to apply to Montana Power;

- HB 25 is silent regarding the status of small customers who have chosen a supplier other than NorthWestern.

- The repeal of 69-8-403, MCA, would invalidate the PSC's default electric supplier procurement guidelines, ARM 38.5.8201 to 8229.

I refer you to the attachment to my written testimony for the PSC's detailed comments and concerns about various provisions of this bill.

Again, thank you Mr. Chairman and committee members for the opportunity to testify here today. I believe that the reintegration of NorthWestern may be the single most important issue to come before this legislative session. For that reason, getting the details right is all the more important. I am aware that a great deal of work has already been done to that end.

I believe that there are currently four Chapter 8 reform bills. HB 434 contains the changes to title 69, chapter 8 that the Public Service Commission believes are necessary to best accomplish the task. SB 195 takes still another approach. LC 1103 is close to being introduced and is the product of long and serious negotiations by various parties. I urge the Committee to take a long, hard look at all of these bills to ensure that the statutory framework for reintegration

that emerges from this legislative session fairly balances the needs of NorthWestern and ratepayers and incorporates sound regulatory policy going forward.

Thank you for the opportunity to comment.

PSC COMMENTS & RECOMMENDED CHANGES REGARDING HB 25

Section 1. Amends the definition of "transmission services provider" in Title 15 to remove the reference to a definition of the term in Title 69, Chapter 8, that is eliminated in this bill.

> PSC comment: It is redundant for the amended definition of "transmission services provider" to include an "entity" in addition to a "person" because the term "person" immediately preceding this definition is already defined to include entities.

Section 5. Eliminates most of Chapter 8's existing legislative findings and policy, but retains policy declarations that adequate, reliable electricity must be provided to small consumers at the lowest long-term total cost and that the financial integrity of electrical utilities must be fostered.

> PSC comments: The PSC recommends repeal of this section altogether. The aim of the Chapter 8 reform bills, including this one, is to return NorthWestern Energy to a full-service utility that is subject to the traditional public utility regulation of Title 69, Chapter 3, which makes it unnecessary to include any special legislative declarations in Chapter 8. The declaration that adequate, reliable service must be provided to **small** customers is more narrow than the requirement in 69-3-201 that such service must be provided to all utility customers. The definition of "small customer" is also deleted in Section 6. The declaration that the utility's financial integrity must be fostered was understandable in the context of SB 390 back in 1997 because it was feared that restructuring would result in stranded costs and other possible adverse financial impacts on the utility. However, inclusion of this declaration in HB 25 could elevate this regulatory objective above all others.

Section 6. Amends the Definitions section of Chapter 8.

> PSC comments: The PSC has several major concerns about this section, as enumerated below. The PSC recommends deleting the identified definitions.
>
> 1. The definition of the term "electricity supply costs" is extremely problematical for these reasons:
>
> - The term is apparently defined in order to identify the costs in Section 8 of the bill for which the PSC is required to establish a cost recovery mechanism known as a "tracker." The PSC has used trackers for years to provide timely recovery of a utility's volatile costs that are beyond its control, such as fuel and purchased power costs; however, a tracker is not appropriate for known, stable and predictable utility costs. This problem is exacerbated by including in this definition the revenue requirement for utility-owned or leased generation facilities, which includes capital costs, operating costs (e.g., maintenance, labor, administration), and unspecified other costs that should not be recovered in a tracker, as well as the inclusion of the costs of "electricity supply service," which is subsequently defined so broadly as to potentially include every aspect of electric utility service.

- In any case, there is no reason to define the term "electricity supply costs." The PSC has not needed a definition of supply costs in its long history of identifying and calculating relevant utility costs as an integral part of the PSC's duty to establish just and reasonable rates that protect consumers and allow utilities to recover prudent costs and earn a reasonable return. This bill is meant to transition NorthWestern to the Chapter 3 traditional regulatory framework it was subject to prior to restructuring – the same framework that applies to MDU and Energy West. Chapter 3 does not include a definition of this term.

2. "Electricity supply service" is defined as "the provision of electricity supply and related services." The definition's inclusion of "and related services" makes the term unworkably broad.

3. The definition of "new electricity supply resource" includes both utility power purchase agreements and generation plant ownership, which results in both arrangements inappropriately being treated the same for regulatory purposes in the pre-approval section of the bill (Section 10).

Section 7. Amends the customer choice section to: eliminate provisions regarding the transition to customer choice; prohibit a large choice customer or new large customer from returning to or obtaining electricity supply from a public utility unless the utility agrees to provide it after the large customer demonstrates other customers' rates will not be adversely affected as determined by the PSC; prohibits a returning or new large customer that obtains utility electricity supply service from switching to another electricity supply service provider; and maintains the MDU exemption from most of Chapter 8's provisions.

PSC comments: The public utility should be required to supply electricity to a large customer that demonstrates there would be no adverse impacts to the utility's customers as determined by the PSC if the large customer obtained electricity supply from the utility. Subsection (1)(b) provides that the utility may agree (or not) to supply electricity to the large customer in this instance.

Also in (1)(b), the PSC prefers that a large customer seeking public utility supply service be required to demonstrate to the PSC that provision of electricity supply by the utility to the large customer would produce "net utility system benefits over the long term," which is a broader and more affirmative standard than the showing in HB 25 of no adverse rate impacts.

There should be a provision in this section concerning small customers who have moved to choice to resolve the issue of their ability to return to public utility supply service. In addition, the PSC bill (HB 434) has a provision in this section that says "nothing in this section affects customers' rights and obligations related to net metering, co-generation, etc." HB 25 does not include a provision like this, but should.

Section 8. Amends 69-8-210, MCA, to delete most of the section's provisions, except for the requirements that the PSC establish an electricity cost tracker and that public utilities offer a "green power" option to customers.

PSC comments: The PSC urges the deletion of subsection (1), which is the provision that requires the PSC to establish a tracker mechanism for NorthWestern's prudently incurred electricity supply costs. See the comments above on Section 6's overly broad definition of "electricity supply costs."

The PSC strenuously objects to the idea of everything flowing through a monthly electric tracker. It is bad policy because the purpose of effective utility regulation is to only allow legitimate costs to flow into rates. The purpose of regulation is not to pass through all costs to customers. This tracker requirement for electricity supply costs would have the impact of a general rate case each month. Not only is that bad policy, but it is administratively impossible because there simply would not be time to review and rule on each tracker filing.

While it is reasonable to use a tracker to allow a utility to recover certain volatile fuel costs and power purchase costs, it is neither reasonable nor efficient to require tracking of all kinds of costs related to utility-owned generation. In addition, the PSC has established natural gas trackers without explicit statutory authority for many years. This provision is bad policy and unnecessary when the objective of this bill is to return NorthWestern to the traditional regulatory model that has demonstrated over many years its effectiveness in balancing the utility's and ratepayers' interests.

Section 10. Amends the resource planning and procurement provisions of 69-8-419, MCA, to remove references to "default supply" and replace the term "default supplier" with "public utility."

PSC comments: This NorthWestern-specific resource planning section should be repealed because there are very similar existing statutory provisions in Chapter 3, Part 12, regarding electric utilities' integrated resource planning (IRP). MDU has been subject to the IRP requirements for many years, as was Montana Power (now NorthWestern) prior to restructuring.

Section 11. Amends another resource planning section of 69-8-420, MCA, to remove references to "default supply" and replace the term "default supplier" with "public utility."

PSC comment: Repeal this section for the same reasons that Section 10 should be repealed.

Section 12. Amends 69-8-421, MCA, to extend the preapproval provisions that exist now for power purchase agreements to the broader category of "new electricity supply resources," which is defined to include "an equity interest in a new or existing electric energy generation facility" as well as power purchase agreements.

PSC comments: Section 13 of HB 434 (the PSC bill) does a better job of amending 69-8-421 to provide for regulatory treatment of NorthWestern's resource procurement activities, which under both bills could include ownership of generation, than does this section of HB 25. Our specific concerns include:

1. The PSC has long-standing concerns regarding preapproval of utilities' resource acquisitions, but has conceded the point in the PSC bill (HB 434) in recognition of NorthWestern's strong preference that preapproval continue to be an option during its transition to a traditionally regulated vertically integrated utility. However, because the definition of "new electricity supply resource" includes both power purchase agreements and utility ownership or lease of generation, HB 25 extends the existing requirement that the PSC act on pre-approval requests for power purchase agreements within 180 days to pre-approval requests for generation ownership or lease. One hundred eighty days is simply not sufficient time to adequately consider and act on a request for pre-approval of a new generation plant.

2. Subsection (2)(c)(iii) requires a PSC preapproval order to include a finding that certain contract terms related to the price, quantity and duration of the new electricity supply resource are reasonable. This provision is appropriate in the current law that concerns preapproval of power purchase agreements, but it not appropriate when a contract is not involved, as would be the case when the new supply resource is utility owned or leased generation.

3. Subsection (5) requires the PSC to judge the prudence of NorthWestern's resource procurement actions for which the utility has not sought preapproval in the utility's cost recovery filings pursuant to 69-8-210, MCA. The PSC recommended in its comments on Section 8 that the cost tracker requirement for electricity supply costs in 69-8-210 be deleted. For the same reasons, we recommend deletion of this subsection in Section 12.

Section 14. Repeals numerous sections of Chapter 8.

PSC comments: Repeal of Section 69-8-403 will result in invalidation of the PSC's current default supplier planning and procurement rules that were adopted pursuant to subsection 8 of this section. The PSC bill keeps 69-8-403(8).

Section 69-8-411, which requires a distribution services provider like NorthWestern to provide nondiscriminatory access for electricity suppliers to the utility's distribution facilities, should not be repealed. The PSC bill, HB 434, keeps the nondiscriminatory access provisions to ensure that non-utility generators and electricity suppliers continue to have fair and open access to NorthWestern's transmission and distribution facilities. (See Section 17 of HB 434.)

EXHIBIT 17
DATE 1-24-07
HB 25

EXECUTIVE SUMMARY

R. W. Beck, Inc. (R. W. Beck) was retained by the City of Great Falls, Montana to analyze the financial impact of customers changing their electric supplier from NorthWestern Energy (NWE) to Electric City Power of Great Falls[1] (Great Falls). Specifically, R. W. Beck evaluated how customer migration from NWE to Great Falls would affect the energy and capacity supply costs paid by NWE's remaining Default Supply customers.

NWE is the current default supplier, and under current Montana law all small and most mid-sized electricity customers in NWE's service territory must purchase their electricity from the default supplier.[2] NWE and others raised concerns in connection with legislation in the 2005 Montana legislature which was designed to allow the City of Great Falls (the City) to serve customers in and around the City, arguing that NWE had the economies of scale and diversity of supply that enabled NWE to provide energy more efficiently. Opponents of Great Falls' efforts have also contended that allowing customers to switch from NWE to Great Falls may have a negative financial impact on the rest of NWE's 300,000 Default Supply customers by increasing the energy and capacity supply costs paid per customer.

Our analysis of NWE's 2003 Electric Default Supply Resource Plan (NWE's 2003 Plan) and NWE's 2005 Electric Default Supply Procurement Plan (NWE's 2005 Plan), including historical load levels and market purchases, indicates that the financial argument for opposing the migration of Great Falls customers from the Default Supply is largely invalid. Our results show that if NWE's expected Default Supply load requirements remain at the projected Base Case levels, any demand decrease resulting from customers migrating from NWE to Great Falls, including the scenario of removing the entire Great Falls energy and capacity requirements, will

---

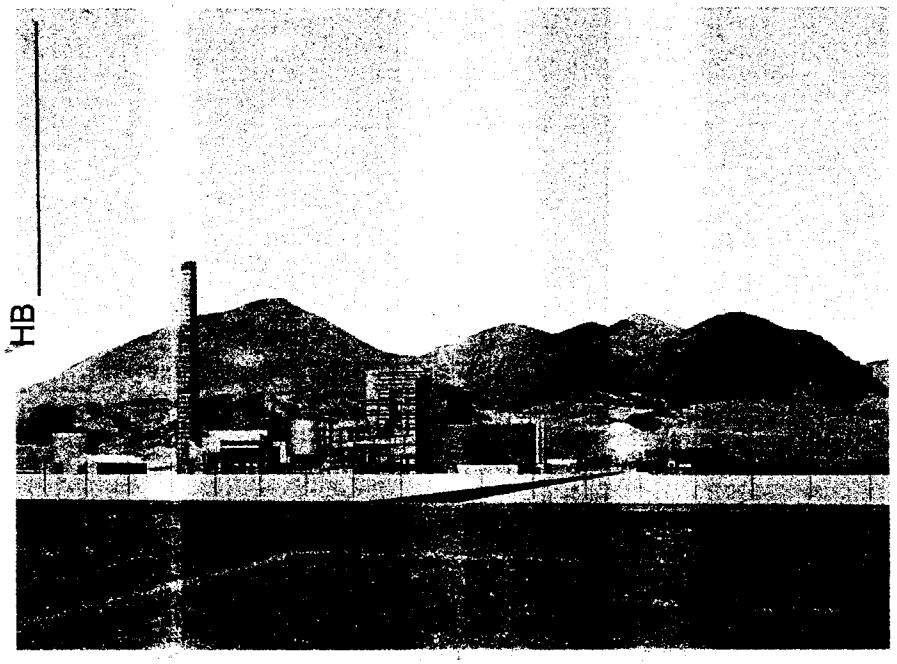
1 In June of 2003, NWE unilaterally canceled supply contracts with Montana cities and schools. In August of 2003, Electric City Power was established by ordinance, and in October, the City joined Southern Montana Electric Generation and Transmission Cooperative (SME). The City applied for a license and, in October 2004, received its license from the Montana Public Service Commission (PSC) to supply electricity to large commercial customers. Then in the spring of 2005, House Bill 642, which would have allowed the City to become an electric utility and serve its own residents, was defeated in the Montana House of Representatives.

2 Currently the City's operation is supplying over 5 MW to customers, which include the Great Falls Public School District, the Airport Authority, FedEx, and the Montana Air National Guard, through 2008. The City began to add another 10 MW for additional customers in September 2005. The City submitted a petition to the Public Service Commission to operate a small customer supply program that would include 10 to 15 small commercial and residential customers representing about 15,000 kW annual average usage.

result in a positive financial impact to NWE's remaining Default Supply customers. NWE's exposure to volatile spot markets will be decreased and NWE will have to make fewer spot market energy and capacity purchases to meet Default Supply customer requirements, which is a stated goal of its planning process.[3]

[3] NWE's 2003 Plan Summary of January 2004 states, "The primary concern regarding the current electricity supply is the portion not under contract which is purchased from the market ... We'd hate to get caught like California did a few years ago, paying huge amounts for short-term purchases ... long-term contracts make sense when a utility, like NWE, doesn't own generators." NWE's 2005 Plan (Docket No. N2005.12.172) of December 2005 states, "Without generation resources, NWE must turn to the wholesale market to buy electricity at market prices to serve its customers. As a result, the rates customers pay reflect the market price that NWE pays for electricity."

EXHIBIT 18
DATE 1-24-07
HB



Proposed Highwood Generating Station

City of Great Falls

John Lawton
City Manager
City of Great Falls
Phone: 406-455-8450
jlawton@ci.great-falls.mt.us

10 Reasons

Why Great Falls is Involved in Electrical Energy—including Customer Choice and Generation

1. The City believes it needs to control its own energy costs to the extent possible. For example, NorthWestern Energy unilaterally cancelled the City's long-term energy supply contract in 2003, costing the City over $1 million over a five-year period.

2. Local taxpayers and ratepayers benefit from the City providing lower cost electricity to governmental entities such as Great Falls Public Schools, City water and wastewater systems, and the Great Falls International Airport.

3. The local economy benefits when major employers have access to stable, reasonably priced electricity. It helps make Great Falls economically competitive.

4. The City is helping to establish a small niche for public power in energy supply. Every Western state plus the Dakotas and Nebraska has some provision for public power except Montana. Other states view a mix of power providers, including investor-owned utilities, rural electric cooperatives, and public power agencies as benefiting consumers through controlled competition.

5. Involvement in electricity generation will help Great Falls expand its economic cluster of energy-related businesses to position the region as an energy center in Montana.

6. Having base load generation in the Great Falls area will help encourage other energy development, including renewable energy resources, by providing shared services and resources.

7. The Highwood Generating Station will provide several hundred construction jobs for at least three years and 65 permanent jobs in Cascade County.

8. The power plant will provide a substantial addition to the tax base of Cascade County for the improvement of infrastructure and services.

9. The generating station will require substantial new infrastructure such as water and sewer lines. This new infrastructure will help attract other business and industry to Great Falls and Cascade County.

10. The Highwood Generating Station will demonstrate that a facility using Montana coal and the best available emissions control technology can be built and operated in an environmentally responsible manner while having no significant adverse impact on air and water quality

MINUTES

MONTANA HOUSE OF REPRESENTATIVES
60th LEGISLATURE - REGULAR SESSION

COMMITTEE ON FEDERAL RELATIONS, ENERGY, AND TELECOMMUNICATIONS

Call to Order: By **CHAIRMAN ALAN OLSON**, on February 12, 2007 at 3:00 P.M., in Room 172 Capitol.

ROLL CALL

Members Present:

Rep. Alan Olson, Chairman (R)
Rep. George G. Groesbeck, Vice Chairman (D)
Rep. Harry Klock, Vice Chairman (R)
Rep. Scott Boggio (R)
Rep. Robyn Driscoll (D)
Rep. Dave Gallik (D)
Rep. Dennis Himmelberger (R)
Rep. Llew Jones (R)
Rep. Diane Rice (R)
Rep. Wayne Stahl (R)
Rep. Bill Thomas (D)
Rep. Jonathan Windy Boy (D)

Members Excused: None.

Members Absent: None.

Staff Present: Todd Everts, Legislative Branch
Cindy Peterson, Committee Secretary

Audio Committees: These minutes are in outline form only. They provide a list of participants and a record of official action taken by the committee. The link to the audio recording of the meeting is available on the Legislative Branch website.

Committee Business Summary:

Hearing & Date Posted: HB 558, 2/5/2007
Executive Action: HB 25

HEARING ON HB 558

Opening Statement by Sponsor:

00:01:03 Rep. Franke Wilmer (D), HD 64, opened the hearing on HB 558, Purchase of fuel efficient vehicles by state.
EXHIBIT(feh31a01)

Proponents' Testimony:

00:09:07 Matt Leow, MontPIRG
00:12:55 Matt Elsaesser, SAV Foundation
00:14:16 Chuck Magraw, Natural Resource Defense Council and Renewable Northwest Project

Opponents' Testimony: None

Informational Testimony: None

Questions from Committee Members and Responses:

00:16:16 Rep. Driscoll
00:16:49 Rep. Wilmer
00:17:27 Rep. Olson
00:17:48 Rep. Wilmer
00:18:46 Rep. Olson
00:19:05 Rep. Wilmer

Closing by Sponsor:

00:19:17 Rep. Wilmer

00:21:14 Break
00:24:27 Reconvene

EXECUTIVE ACTION ON 25

Discussion:

00:26:14 Rep. Stahl
00:26:40 John Fitzpatrick, Northwestern Energy
00:42:15 Rep. Jones
00:43:32 Doug Mood, Commissioner, Montana Public Service Commission, (PSC)
EXHIBIT(feh31a02)
00:51:03 Rep. Jones
00:52:06 Commissioner Mood
00:54:42 Rep. Gallik

00:56:41 Commissioner Mood
00:58:23 Rep. Gallik
00:59:36 Commissioner Mood
01:01:14 Rep. Gallik
01:01:55 Commissioner Mood
01:02:02 Rep. Gallik
01:02:25 Commissioner Mood
01:02:32 Al Brogan, PSC
01:03:00 Rep. Gallik
01:03:35 Mr. Brogan
01:04:08 Rep. Driscoll
01:04:30 Commissioner Mood
01:05:00 Rep. Driscoll
01:05:13 Commissioner Mood
01:05:55 Rep. Himmelberger
01:06:38 Brad Molnar, Commissioner, PSC
01:13:24 Rep. Himmelberger
01:13:55 David Hoffman, PPL Montana
01:17:58 Rep. Olson
01:18:20 Mr. Hoffman
01:19:44 Rep. Olson
01:19:50 Mr. Hoffman
01:20:06 Rep. Olson
01:20:15 Mr. Hoffman
01:20:33 Rep. Olson
01:21:32 Mr. Hoffman
01:22:37 Rep. Olson
01:22:53 Mr. Hoffman
01:23:57 Rep. Olson
01:24:07 Mr. Hoffman
01:24:53 Rep. Olson
01:25:04 Mr. Hoffman
01:26:25 Rep. Stahl
01:26:37 Mr. Hoffman
01:27:11 Rep. Stahl
01:27:24 Mr. Hoffman
01:28:02 Rep. Himmelberger
01:28:25 Doug Hardy, Montana Electric Cooperatives
01:28:55 Rep. Himmelberger
01:29:03 Mr. Hardy
01:29:17 Rep. Olson
01:29:43 Mr. Fitzpatrick
01:31:32 Rep. Olson
01:31:43 Mr. Fitzpatrick
01:33:45 Rep. Gallik
01:34:09 Mr. Fitzpatrick
01:34:23 Rep. Gallik
01:34:34 Mr. Fitzpatrick
01:35:49 Rep. Gallik

01:36:14 Mr. Fitzpatrick
01:37:07 Rep. Groesbeck
01:38:34 Mr. Fitzpatrick
01:40:32 Rep. Stahl
01:41:18 Mr. Fitzpatrick

01:42:10 **Motion**: Rep. Groesbeck moved that HB 25 **DO PASS AS AMENDED**. (Previous executive action was taken on HB 25 on February 2, February 5, and February 7, 2007.)

Discussion:

01:42:46 Rep. Boggio
01:43:54 Rep. Gallik
01:46:09 Rep. Olson

01:50:11 **Vote**: Motion carried 8-4 by roll call vote with Rep. Boggio, Rep. Gallik, Rep. Stahl, and Rep. Thomas voting no.

ADJOURNMENT

01:51:15 Adjournment

REP. ALAN OLSON, Chairman

CINDY PETERSON, Secretary

AO/cp

Additional Exhibits:

EXHIBIT(feh31aad.pdf)

EXHIBIT 2
DATE 2-12-07
HB 25

Public Service Commission Comments on the Amendments to HB 25
February 12, 2007

The amended HB 25 improves the bill in these major areas:

69-8-102 repeal (amendment #11). The amended HB 25 improved by this repeal of Chapter 8's existing legislative findings and policy section in its entirety. The aim of the Chapter 8 reform bills, including this one, is to return NorthWestern Energy to a full-service utility that is subject to the traditional public utility regulation of Title 69, Chapter 3, which makes it unnecessary to include any special legislative declarations in Chapter 8.

Section 6. The definition of the term "electricity supply costs" now includes only costs related to power purchase agreements, demand-side management and energy efficiency programs. This is an improvement over the term as defined in HB 25 as introduced which was, in concert with the definition of "electricity supply service" so broadly defined as to potentially include every aspect of electric utility service. The definition as amended means that the mandatory cost tracker provision in 69-8-210 (Section 8 of the bill) applies only to the reduced list of "electricity supply costs."

Section 7. Amendment #27 improves HB 25 because it is now mandatory, not permissive, concerning the public utility's obligation to supply electricity to a large customer that demonstrates there would be no adverse impacts to the utility's customers as determined by the PSC if the large customer obtained electricity supply from the utility.

Amendment #29 addresses the PSC's concern that there should be a provision in this section concerning small customers who have moved to choice to resolve the issue of their ability to return to public utility supply service.

Sections 10 and 11. Amendment #33 is important because: (1) it retains the PSC's rulemaking authority under which the current default supply planning and procurement rules were implemented, and (2) it adds nondiscriminatory access provisions to ensure that non-utility generators and electricity suppliers continue to have fair and open access to NorthWestern's transmission and distribution facilities.

Section 14. The amendments to this section improve HB 25 by removing the provisions that extended the existing requirement that the PSC act on approval requests for power purchase agreements within 180 days to approval requests for generation ownership or lease. In the amended HB 25, the PSC must act within 180 days on an application for a power purchase agreement from an existing generating resource, but has 270 days, plus 90 days if necessary, to act on an application for approval of utility-owned or leased generation or a power purchase agreement from a new generation resource.

Amendment #55 allows PSC approval of an application to be "in whole or in part," which importantly provides the PSC with some flexibility when considering these applications.

Montana House of Representatives
Visitors' Register

FEDERAL RELATIONS, ENERGY, AND TELECOMMUNICATIONS COMMITTEE **Date** 2/12/07

Bill Nos. 558 **Sponsor(s)** Wilmut

PLEASE PRINT **PLEASE PRINT** **PLEASE PRINT**

Name	Representing	Bill No.	Support	Oppose	Info.
Matt Elsaesser	SAVE Fnd	558	X		
CHUCK MAGRAW	NRDC + RNP	558	X		
PATRICK JUDGE	MEIC	558	X		
Matt Leow	MontPIRG	558	X		

Please leave prepared testimony with Secretary. Witness Statement forms are available if you care to submit written testimony.

HOUSE OF REPRESENTATIVES
Roll Call
FEDERAL RELATIONS, ENERGY, AND TELECOMMUNICATIONS COMMITTEE

DATE: 2.12.07

NAME	PRESENT	ABSENT/ EXCUSED
REP. ALAN OLSON, CHAIR	✓	
REP. HARRY KLOCK, VICE CHAIR	✓	
REP. GEORGE GROESBECK, VICE CHAIR	✓	
REP. SCOTT BOGGIO	✓	
REP. ROBYN DRISCOLL	✓	
REP. DAVE GALLIK	✓	
REP. DENNIS HIMMELBERGER	✓	
REP. LLEW JONES	✓	
REP. DIANE RICE	✓	
REP. WAYNE STAHL	✓	
REP. BILL THOMAS	✓	
REP. JONATHAN WINDY BOY	✓	

HOUSE STANDING COMMITTEE REPORT

Mr. Speaker:

We, your committee on **Federal Relations, Energy, and Telecommunications** recommend that **House Bill 25** (first reading copy -- white) **do pass as amended**.

Signed: _____
Representative Alan Olson, Chair

And, that such amendments read:

1. Title, line 6 through line 7.
Strike: "CLARIFYING" on line 6 through "PROVISIONS;" on line 7

2. Title, line 10.
Strike: "PREAPPROVAL"
Insert: "APPROVAL"
Strike: "NEW"

3. Title, line 11.
Following: "RESOURCES;"
Insert: "CLARIFYING USE OF GENERATION ASSETS;"
Following: "35-19-102,"
Insert: "69-1-114,"
Strike: "69-8-102,"

4. Title, line 12.
Following: "69-8-311,"
Insert: "69-8-403, 69-8-411,"

5. Title, line 12.
Following: "69-8-421,"
Insert: "69-8-602, 69-8-603,"

6. Title, line 13.
Following: "SECTIONS"
Insert: "69-8-102,"

Committee Vote:
Yes 8, No 4
Fiscal Note Required ___

320957SC.hjd
2/13/07

7. Title, line 14.
Strike: "69-8-401, 69-8-403,"
Following: "69-8-409,"
Insert: "AND"

8. Title, line 15.
Strike: "AND 69-8-411,"

9. Page 1, line 26.
Following: "line"
Insert: "or substation"

10. Page 4, line 5.
Insert: "**Section 4.** Section 69-1-114, MCA, is amended to read:
"**69-1-114. Fees.** (1) Each fee charged by the commission must be reasonable.
(2) Except for a fee assessed pursuant to 69-3-204(2), ~~69-8-421(7)~~ 69-8-421(9), or 69-12-423(2), a fee set by the commission may not exceed $500.
(3) All fees collected by the department under ~~69-8-421(7)~~ 69-8-421(9) must be deposited in an account in the special revenue fund. Funds in this account must be used as provided in ~~69-8-421(7)~~ 69-8-421(9)."
Renumber: subsequent sections

11. Page 4, line 8.
Strike: "Transition"
Insert: "Generation Reintegration"

12. Page 4, line 10 through page 5, line 4.
Strike: section 5 in its entirety
Renumber: subsequent sections

13. Page 6.
Following: line 6
Insert: "(5) "Distribution facilities" means those facilities by and through which electricity is received from transmission facilities and distributed to a retail customer and that are controlled or operated by a utility."
Renumber: subsequent subsections

14. Page 6, line 7.
Strike: "of"
Insert: "incurred in"
Following: "service"
Insert: "through power purchase agreements, demand-side management, and energy efficiency programs"

15. Page 6, line 13.

Strike: subsection (e) in its entirety
Renumber: subsequent subsections

16. Page 6, line 15.
Strike: subsections (g) in its entirety
Renumber: subsequent sections

17. Page 6, line 16.
Following: ";"
Insert: "and"

18. Page 6, line 17 through page 6, line 18.
Strike: subsection (i) in its entirety
Renumber: subsequent subsections

19. Page 6, line 20.
Following: "~~default~~"
Strike: remainder of line 20
Insert: "power purchase agreements.
(7) "Electricity supply resource" means:
(a) contracts for electric capacity and generation;
(b) plants owned or leased by a utility or equipment used to generate electricity;
(c) customer load management and energy conservation programs; or
(d) other means of providing adequate, reliable service to customers, as determined by the commission."
Renumber: subsequent subsections

20. Page 6, line 21.
Following: "<u>services</u>"
Insert: "through power purchase agreements, the acquisition and operation of electrical generation facilities, demand-side management, and energy efficiency programs"

21. Page 7.
Following: line 7
Insert: "(11) "Generation assets cost of service" means a return on invested capital and all costs associated with the acquisition, construction, administration, operation, and maintenance of a plant or equipment owned or leased by a public utility and used for the production of electricity."
Renumber: subsequent subsections

22. Page 7, line 23.
Strike: "distribution services provider's"
Insert: "utility's"

23. Page 7, line 25 through page 7, line 26.
Strike: subsection (15) in its entirety

Renumber: subsequent subsections

24. Page 8, line 3.
Following: "~~assignees~~"
Insert: ", on May 2, 1997, including the public utility's successors or assignees"

25. Page 9.
Following: line 22
Insert: "(28) "Transmission facilities" means those facilities that are used to provide transmission services as determined by the federal energy regulatory commission and the commission and that are controlled or operated by a utility."
Renumber: subsequent subsections

26. Page 10, line 6.
Following: "**customer**"
Insert: "electricity supply service"

27. Page 10, line 29.
Following: "supply"
Insert: "service"

28. Page 11, line 9.
Strike: "may agree to"
Insert: "must"

29. Page 11, line 10.
Following: "impact"
Strike: "the rates of"

30. Page 12.
Following: line 12
Insert: "(2) (a) A retail customer that has an individual load with an average monthly demand of less than 5,000 kilowatts and that is not purchasing electricity from a public utility on [the effective date of this act] may continue to purchase electricity from an electricity supplier. The retail customer may subsequently purchase electricity from a public utility subject to commission rule or order, but the customer may not, at a later date, choose to purchase electricity from another source.

(b) A retail customer that has an individual load with an average monthly demand of less than 5,000 kilowatts and that is currently purchasing electricity from a public utility may not choose to purchase electricity from another source after [the effective date of this act].

(3) Nothing in this section affects a retail customer's rights and obligations with respect to net metering,

cogeneration, self-generation, or ancillary sales of electricity related to deviations from scheduled energy deliveries from nonutility suppliers, as may be provided for in law, commission rule or order, or a tariff approved by the public service commission or the federal energy regulatory commission."
Renumber: subsequent subsections

31. Page 12, line 14.
Strike: "(2)(b)"
Insert: "(4)(b)"

32. Page 12, line 18.
Strike: "(2)(a)"
Insert: "(4)(a)"

33. Page 13, line 1.
Strike: "and"
Insert: ","
Following: "69-8-420"
Insert: ", and commission rules. The commission may include other utility costs and expenses in the cost recovery mechanism if it determines that including additional costs and expenses is reasonable and in the public interest"

34. Page 14, line 1.
"Section 10. Section 69-8-403, MCA, is amended to read:
"69-8-403. Commission ~~authority --~~ rulemaking authority.
~~(1) Beginning on the effective date of a commission order regarding a public utility's transition plan, the commission shall regulate the public utility's retail transmission, distribution, and default supply services within the state of Montana, as provided in this chapter.~~
~~(2) The commission shall license electricity suppliers and enforce licensing provisions pursuant to 69-8-404.~~
~~(3) The commission shall promulgate rules that identify the licensees and ensure that the offered electricity supply is provided as offered and is adequate in terms of quality, safety, and reliability.~~
~~(4) The commission shall establish just and reasonable rates through established ratemaking principles for public utility default supply, distribution, and transmission services and shall regulate these services. The commission may approve rates and charges for those services based on alternative forms of ratemaking such as performance-based ratemaking, on a demonstration by the public utility that the alternative method complies with this chapter, and on the public utility's transition plan.~~
~~(5) The commission shall certify that a cooperative utility has adopted a transition plan that complies with this chapter. A cooperative utility's transition plan is considered certified 60~~

~~days after the cooperative utility files for certification.~~

~~(6) The commission shall promulgate rules that protect consumers, distribution services providers, and electricity suppliers from anticompetitive and abusive practices.~~

~~(7) (a) After July 1, 2010, the commission shall continuously monitor whether or not workable competition has developed for small customers.~~

~~(b) If the commission determines that workable competition has developed for small customers after July 1, 2010, the commission shall provide a report to the legislature that includes recommendations for legislative implementation of customer choice for small customers.~~

~~(8)~~ In addition to promulgating rules expressly provided for in this chapter, the commission may promulgate any other rules necessary to carry out the provision of this chapter.

~~(9) This chapter does not give the commission the authority to:~~

~~(a) regulate cooperative utilities in any manner other than reviewing certification filings for compliance with this chapter; or~~

~~(b) compel any change to a cooperative utility's certification filing made pursuant to this chapter.~~"

Insert: "Section 11. Section 69-8-411, MCA, is amended to read:

"69-8-411. Nondiscriminatory access ~~-- reciprocity.~~ ~~Except as provided in 69-8-311, all electricity suppliers must be afforded open, fair, and nondiscriminatory access to customers and a comparable opportunity to compete. A distribution services provider or the distribution services provider's affiliates may not use another distribution services provider's facilities in the state of Montana to sell electricity to customers in the state of Montana unless the first distribution services provider or the distribution services provider's affiliates offer comparable and nondiscriminatory access to the distribution services provider's distribution facilities within the state of Montana.~~ (1) Nonutility generators and electricity suppliers must have open, fair, and nondiscriminatory access to a public utility's transmission and distribution facilities according to federal energy regulatory commission rules and regulations for purposes of serving those customers identified in 69-8-201(1) and (2).

(2) Public utilities shall grant the retail customers identified in 69-8-201(1) and (2) and their electricity suppliers access to transmission and distribution facilities at rates and under terms and conditions comparable to the public utility's own access to those facilities or access by the public utility's affiliates.

(3) Public utilities shall file tariffs for transmission and distribution services regulated by the federal energy regulatory commission and the commission implementing subsections (1) and (2)."

Renumber: subsequent sections

35. Page 14, line 17.
Following: "service"
Insert: "and related services"

36. Page 14, line 18.
Following: "~~the~~"
Strike: "The"
Insert: "By December 31, 2007, the"

37. Page 14, line 28.
Following: "~~agreement~~"
Strike: "preapproval of a new"
Insert: "approval of an"

38. Page 15, line 3.
Strike: "pursuant to 69-8-419"

39. Page 15, line 5 through page 15, line 6.
Strike: "the rules adopted pursuant to 69-8-419"
Insert: "commission rules"

40. Page 15, line 11 through page 15, line 12.
Following: "with"
Strike: remainder of line 11 through line 12 in their entirety
Insert: "commision rules; and"

41. Page 15, line 16.
Strike: "**Preapproval of new**"
Insert: "Approval of"

42. Page 15, line 18 through page 15, line 19.
Strike: "preapproval of a new"
Insert: "approval of an"

43. Page 15, line 24 through page 15, line 29.
Strike: subsections (2)(a) and (2)(b) in their entirety

44. Page 15, line 30.
Strike: "(c)"
Insert: "(2)"

45. Page 16, line 1.
Strike: "preapproval"
Insert: "approval"

46. Page 16, line 3 through page 16, line 4.
Following: "explain"
Strike: remainder of line 3 through line 4 in their entirety

Insert: "the deficiencies."

47. Page 16, line 5.
Strike: "(d)"
Insert: "(3)"
Following: "application"
Insert: "for approval of a power purchase agreement from an existing generating resource"

48. Page 16.
Following: line 6
Insert: "(4) The commission shall issue an order within 270 days of receipt of an adequate application for approval of a lease, an acquisition of an equity interest in a new or existing plant or equipment used to generate electricity, or a power purchase agreement for which approval would result in construction of a new electric generating resource. The commission may extend the time limit up to an additional 90 days if it determines that extraordinary circumstances require it."

49. Page 16, line 7.
Strike: "(e)"
Insert: "(5)"

50. Page 16, line 9.
Strike: "preapproval"
Insert: "approval"

51. Page 16, line 10.
Strike: "(3)"
Insert: "(6)"
Renumber: subsequent subsections

52. Page 16, line 11.
Strike: "preapproval of a new"
Insert: "approval of an"

53. Page 16, line 14.
Strike: "preapproval of a new electricity supply resource"
Insert: "approval"

54. Page 16, line 15 through page 16, line 16.
Strike: "preapproval of a new electricity supply resource"
Insert: "approval of an application"

55. Page 16, line 17.
Strike: "preapproval of all or part of the ~~agreement~~ new electricity supply resource "

Insert: "approval, in whole or in part,"

56. Page 16, line 18.
Following: ";"
Insert: "and

57. Page 16, line 19 through page 16, line 22.
Strike: subsections (ii) and (iii) in their entirety
Insert: "(ii) procurement of the electricity supply resource is consistent with the requirements in 69-3-201, the objectives in 69-8-419, and commission rules.

(d) The commission order may include a provision for allowable generation assets cost of service when the utility has filed an application for the lease or acquisition of an equity interest in a plant or equipment used to generate electricity."
Renumber: subsequent subsections"

58. Page 16, line 24.
Strike: "preapproval"
Insert: "approval"

59. Page 16, line 25.
Strike: "(3)(c)"
Insert: "(6)(c)"

60. Page 16, line 27.
Strike: "(3)(c)"
Insert: "(6)(c)"

61. Page 16, line 28.
Strike: "incurred under the agreement"
Insert: "related to the approved electricity supply resource"

62. Page 16, line 29 through page 17, line 4.
Strike: subsection (5) in its entirety
Renumber: subsequent subsections

63. Page 17, line 5.
Strike: "cost recovery"
Insert: "rate"

64. Page 17, line 6.
Strike: "and"
Insert: "or"

65. Page 17, line 7.
Strike: "new electricity supply"
Following: "resource"
Insert: "or managed any power supply purchase agreement"

66. Page 17, line 8.
Strike: "electricity supply"
Insert: "rate recovery for the"

67. Page 17, line 10.
Strike: "new"

68. Page 17, line 10 through page 17, line 11.
Following: "in"
Strike: remainder of line 10 through line 11 in their entirety
Insert: "a manner consistent with 69-3-201, 69-8-419, and commission rules."

69. Page 17, line 12.
Following: "independent"
Insert: "engineering, financial, and management"

70. Page 17, line 14.
Strike: "new"

71. Page 17, line 15.
Following: "modeling,"
Strike: "and"
Following: "risk management"
Insert: ", and engineering"

72. Page 17, line 17.
Strike: "electricity supply service"

73. Page 17, line 18 through page 17, line 19.
Strike: subsection (8) in its entirety
Insert: "(10) By December 31, 2007, the commission shall adopt rules prescribing minimum filing requirements for applications filed pursuant to this part."

74. Page 17, line 20.
Insert: **"Section 15.** Section 69-8-602, MCA, is amended to read:
"69-8-602. ~~Distribution services provider~~ Utility net metering requirements. A ~~distribution services provider~~ utility shall:
(1) allow net metering systems to be interconnected using a standard kilowatt-hour meter capable of registering the flow of electricity in two directions, unless the commission determines, after appropriate notice and opportunity for comment:
(a) that the use of additional metering equipment to monitor the flow of electricity in each direction is necessary and appropriate for the interconnection of net metering systems, after taking into account the benefits and costs of purchasing and installing additional metering equipment; and

(b) how the costs of net metering are to be allocated between the customer-generator and the ~~distribution services provider~~ utility; and

(2) charge the customer-generator a minimum monthly fee that is the same as other customers of the electric utility in the same rate class. The commission shall determine, after appropriate notice and opportunity for comment if:

(a) the ~~distribution services provider~~ utility will incur direct costs associated with interconnecting or administering net metering systems that exceed any offsetting benefits associated with these net metering systems; and

(b) public policy is best served by imposing these costs on the customer-generator, rather than allocating these costs among the ~~distribution services provider's~~ utility's entire customer base.""

Insert: "Section 16. Section 69-8-603, MCA, is amended to read:

"69-8-603. Net energy measurement calculation. Consistent with the other provisions of this part, the net energy measurement must be calculated in the following manner:

(1) The ~~distribution services provider~~ utility shall measure the net electricity produced or consumed during the billing period, in accordance with normal metering practices.

(2) If the electricity supplied by the electricity supplier exceeds the electricity generated by the customer-generator and fed back to the electricity supplier during the billing period, the customer-generator must be billed for the net electricity supplied by the electricity supplier, in accordance with normal metering practices.

(3) If electricity generated by the customer-generator exceeds the electricity supplied by the electricity supplier, the customer-generator must be:

(a) billed for the appropriate customer charges for that billing period, in accordance with 69-8-602; and

(b) credited for the excess kilowatt hours generated during the billing period, with this kilowatt-hour credit appearing on the bill for the following billing period.

(4) On January 1, April 1, July 1, or October 1 of each year, as designated by the customer-generator as the beginning date of a 12-month billing period, any remaining unused kilowatt-hour credit accumulated during the previous 12 months must be granted to the electricity supplier, without any compensation to the customer-generator.""

Renumber: subsequent sections

75. Page 19, line 24.

Insert: "NEW SECTION. **Section 18. Use of generation assets.** Generation assets acquired by a public utility pursuant to this chapter:

(1) must be used by the public utility to serve and benefit customers within the public utility's Montana service territory; and

(2) may not be removed from the rate base unless the commission finds that customers of the public utility will not be adversely affected."
Insert: "NEW SECTION. **Section 19. Codification instruction.** [Section 18] is intended to be codified as an integral part of Title 69, chapter 8, part 4, and the provisions of Title 69, chapter 8, part 4, apply to [section 18]."
Renumber: subsequent sections

76. Page 19, line 25.
Following: "Sections"
Insert: "69-8-102,"

77. Page 19, line 26.
Strike: "69-8-401, 69-8-403,"

78. Page 19, line 27.
Following: "69-8-409,"
Insert: "and"
Strike: "and 69-8-411,"

- END -

HOUSE OF REPRESENTATIVES
Roll Call Vote
FEDERAL RELATIONS, ENERGY & TELECOMMUNICATIONS COMMITTEE

DATE 2-12-07 BILL NO HB25 MOTION NO. _____

MOTION: HB25 DPAP

NAME	AYE	NO	If Proxy Vote, check here & include signed Proxy Form with minutes
REP. HARRY KLOCK, VICE CHAIR	✓		
REP. GEORGE GROESBECK, VICE CHAIR	✓		
REP. SCOTT BOGGIO		✓	
REP. ROBYN DRISCOLL	✓		
REP. DAVE GALLIK		✓	
REP. DENNIS HIMMELBERGER	✓		
REP. LLEW JONES	✓		
REP. DIANE RICE	✓		
REP. WAYNE STAHL		✓	
REP. BILL THOMAS		✓	
REP. JONATHAN WINDY BOY	✓		
REP. ALAN OLSON, CHAIR	✓		
	8	4	

MINUTES

MONTANA SENATE
60th LEGISLATURE - REGULAR SESSION

COMMITTEE ON NATURAL RESOURCES AND ENERGY

Call to Order: By **CHAIRMAN GREG LIND**, on March 30, 2007 at 3:00 P.M., in Room 422 Capitol.

ROLL CALL

Members Present:

Sen. Greg Lind, Chairman (D)
Sen. Aubyn Curtiss (R)
Sen. Kelly Gebhardt (R)
Sen. Dan Harrington (D)
Sen. Christine Kaufmann (D)
Sen. Gary L. Perry (R)
Sen. Bill Tash (R)
Sen. Mitch Tropila (D)
Sen. David E. Wanzenried (D)

Members Excused: None.

Members Absent: None.

Staff Present: Claudia Johnson, Committee Secretary
Joe Kolman, Legislative Branch

Audio Committees: These minutes are in outline form only. They provide a list of participants and a record of official action taken by the committee. The link to the audio recording of the meeting is available on the Legislative Branch website.

Committee Business Summary:

Hearing & Date Posted:	HB 291, 3/27/2007; HJ 14, 3/27/2007; HJ 31, 3/27/2007; HB 328, 3/27/2007; HB 405, 3/27/2007; HB 25, 3/21/2007
Executive Action:	HJ 14, HB 291

01:41:30 Janet Ellis, Montana Audubon

EXHIBIT(nas68a09)

01:44:06 Joe Brennen, Chairman of the Flathead County Commissioners

01:44:36 Sarah Cobler, Montana Conservation Voters

01:45:20 Evan Barrett, Economic Development, Governor's Office

01:48:06 Russ Doty, Green Buying Cooperative

01:50:27 Chuck Magraw, Natural Resource and Defense Council

Informational Testimony: None.

Questions from Committee Members and Responses:

01:51:42 Sen. Wanzenried to Rep. Lange

Closing by Sponsor:

01:52:03 Rep. Lange

HEARING ON HB 25

Opening Statement by Sponsor:

01:56:27 **REP. ALAN OLSON (R), HD 45**, opened the hearing on **HB 25**, Generally revise electric industry restructuring laws.

Proponents:

01:58:50 Greg Jergeson, Chairman, Public Service Commission (PSC)

EXHIBIT(nas68a10)

02:11:18 Bob Raney, PSC

EXHIBIT(nas68a11)

02:19:12 Doug Mood, PSC

EXHIBIT(nas68a12)

02:31:21 Gerald Mueller, Self

EXHIBIT(nas68a13)

02:39:48 John Fitzpatrick, Northwestern Energy (NWE)

02:45:62 Chuck Magraw, Natural Resource and Defense Council

EXHIBIT(nas68a14)

Opponents:

02:47:18 Ken Toole, PSC

EXHIBIT(nas68a15)

02:49:41 Patrick Judge, Montana Environmental Information Center (MEIC)

02:52:43 David Hoffman, PPL Montana, LLC

EXHIBIT(nas68a16)

03:08:23 Tim Gregori, Manager, Southern Montana Generation and Transmission Cooperative, Inc. (SMGTC)

03:12:14 Alec Hansen, Montana League of Cities and Towns

EXHIBIT(nas68a17)

03:15:58 John Lawton, City Manager, Great Falls

03:18:22 Chuck Magraw, Natural Resource and Defense Council

03:20:13 Bob Nelson, Montana Consumer Counsel

03:31:11 Colleen Balzarler, City of Great Falls

03:33:38 John Prinkki, President of Beartooth Electric Cooperative

03:38:02 Dave Kelsey, Director, Yellowstone Valley Electric

03:39:19 Scott Sweeney, General Manager, Fergus Electric Cooperative

03:43:13 Russell Doty, Executive Director, Green Electricity Cooperative

Informational Testimony:

03:52:47 Brad Molnar, Public Service Commission (PSC)

EXHIBIT(nas68a18)
EXHIBIT(nas68a19)

Questions from Committee Members and Responses:

04:05:59 Sen. Lind to Greg Jergeson, PSC

04:11:11 Will Rosquist, Attorney, PSC

04:14:03 Sen. Curtiss to Rep. Olson

04:15:45 Sen. Curtiss to Tim Gregori, SMGTC

04:18:58 Sen. Curtiss to Bob Raney, PSC

EXHIBIT(nas68a20)

04:22:30 Sen. Harrington to Rep. Olson

04:26:17 Sen. Lind to Gerald Mueller, Self

04:22:30 Sen. Kaufmann to Gerald Mueller, Self

04:36:12 Sen. Kaufmann to Bob Nelson, PSC

04:38:28 Sen. Lind to Bob Nelson, PSC

04:41:50 Sen. Curtiss to Rep. Olson

04:43:14 Sen. Curtiss to Tim Gregori, SMGTC

04:44:07 Sen. Curtiss to Brad Molnar, PSC

04:46:07 Sen. Curtiss to Doug Mood, PSC

04:51:44 Sen. Lind to Doug Mood, PSC

04:56:04 Sen. Lind to John Fitzpatrick, NWE

04:58:58 Sen. Gebhardt to Doug Mood, PSC

05:02:07 Sen. Lind to Will Rosquist, PSC

05:04:33 Sen. Lind to Bob Nelson, PSC

05:06:59 Sen. Gebhardt to John Fitzpatrick, NWE

05:10:47 Sen. Lind to Greg Jergeson, PSC

Closing by Sponsor:

05:13:44 Sen. Olson

EXHIBIT NO. 10
DATE 3-30-07
BILL NO. HB 25

TESTIMONY IN SUPPORT OF HB 25
GENERALLY REVISE ELECTRIC RESTRUCTURING LAWS

Greg Jergeson (406-444-6166)
Chairman, Montana PSC
March 30, 2007

Mr. Chairman and Members of the Committee,

The Public Service Commission supports HB 25 (3-1 vote, and 1 abstention). The Commission is strongly in favor of broad reform of Title 69, Chapter 8. We believe that this legislative session should provide the framework for transitioning NorthWestern Energy from its current status as Montana's sole restructured utility and default electricity supplier, back to an integrated service utility that owns rate-based generation and is traditionally regulated by the PSC. HB 25 as amended by the House achieves the Chapter 8 reform that is so urgently needed.

The default-supply distribution utility, NorthWestern Energy, with no generation assets of its own, has no power at the bargaining table vis-à-vis the merchant generators from whom it must secure supply, particularly PPL Montana. NorthWestern Energy must secure the necessary supply to meet the demand of their customers. That is a legal, practical and moral obligation from which they cannot escape. On the other hand, the unregulated merchant generators have no obligation to sell to the default-supplier and may, can and will pursue the highest prices for their product. Even if the wholesale electricity supply market were reasonably competitive, and that would be one tough assumption to make, with increasing demand outstripping new sources of supply, that market is bound to yield higher prices and higher costs for consumers.

However, as the Montana Consumer Counsel and the Montana PSC have argued before the Federal Energy Regulatory Commission, the wholesale electricity supply market available to NorthWestern Energy is not reasonably competitive. We believe that PPLM exercises market dominance, approaching monopoly power, in the wholesale market available to NorthWestern Energy. Though PPLM cites the FERC decision in their favor as evidence to the contrary, the Montana PSC is convinced the FERC decision is seriously flawed since PPL is able to undercut any offer made by competitors, especially competitors who would need to construct new and expensive facilities, irrespective of the technology employed. Having the ability to drive

competitors from the market, or keep them out in the first place, PPLM is then able to command higher prices from NorthWestern Energy's customers.

The Commission has seen and discussed four of the proposed amendments to HB 25 and opposes them. There are good policy reasons to oppose each of those amendments individually, but our overriding concern is that cluttering up this bill with unnecessary amendments is likely to reduce its support and doom its chances of passage.

Failure to pass HB 25 carries with it adverse consequences for ratepayers and for other Montana energy policy initiatives. If HB 25 does not pass, NorthWestern Energy and its customers will continue for at least two more years to be stuck in the current situation where NorthWestern owns none of its own generation and therefore purchases a significant portion of the electricity it needs to serve Montana customers in the high-priced market. Montana's hopes of taking advantage of our abundant wind resources to generate electricity will be at risk because NorthWestern will not build or acquire its own firming resources that are necessary to integrate wind energy into the grid. Those firming resources and ancillary services are becoming difficult to acquire from other utilities. The statutory fiction that a competitive market exists for small customers will remain in law and continue to create electric load uncertainty that is an impediment to NorthWestern's ability to plan for and procure electricity supply at optimal terms and prices. Unplanned migration of customers to an electricity buying cooperative or municipal utility could result in the creation of new stranded costs which could negatively impact customers remaining in the default supply.

The PSC is convinced that the only way to break the PPLM stranglehold on Montana electricity customers and to act in the interest of Montana ratepayers is to pass HB 25. The PSC believes HB 25 allows for a properly regulated, re-integrated utility serving the interests of Montana electric consumers served by NorthWestern Energy. HB 25 is a reasonable, workable and satisfactory vehicle for an electric utility system that will best serve the Montana electric customers served by NorthWestern Energy. We strongly urge you to support the passage of HB 25.

Thank you for the opportunity to comment.

NorthWestern™ Energy

GREG JERGESON
2540 BELTVIEW DR 104
HELENA MT 59601-5681

Account Number: [redacted]
Bill Date: March 15, 2007
Due Date: March 29, 2007

Previous Balance	Payments/Adjustments	Current Charges	Total Amount Due
$106.00	$106.00 CR	$87.92	$87.92

Account Summary

Regulated Electric Charges	$	40.01
Market Purchased Electric Supply Charges	$	47.91
Total New Charges	**$**	**87.92**

MESSAGE BOARD

- **Effective 3/1/2007, the Market Purchased Electric Supply rate has increased from the previous month.**
- **Why pay for postage? Simply dial TOLL FREE 1-800-218-4959 to pay over the phone. Please have your eight digit account number available when you call.**
- **Questions about your bill or service? Call the NorthWestern Energy Customer Contact Center TOLL FREE at 1-888-467-2669 (Monday through Friday, 7 a.m. - 6 p.m. Mountain Time) or visit us at: www.northwesternenergy.com**

Regulated Electric Charges

Meter Number	Rate Code	From	To	No Days	Previous Reading	Current Reading	Reading Type	Factor	KWh Usage	Demand Usage
ED27487270	E010	02/12/2007	03/13/2007	29	52251	53162	Actual	1	911	

Description	Usage		Rate ($)	Total
Res: Transmission Delivery	911.0	@	0.0085790	$7.82
Res. Service Charge				$4.87
Res. Distribution Delivery	911.0	@	0.0267030	$24.33
Res. BPA Exchange Credit	911.0	@	0.0015110-	$1.38CR
Res. CTC-QF	911.0	@	0.0034590	$3.15
Res. USBC	911.0	@	0.0013340	$1.22
Total Regulated Electric Charges				**$40.01**

Market Purchased Electric Supply Charges

Description	Usage		Rate ($)	Total
Res. Supply	503.0	@	0.0505370	$25.42
Res. Supply	408.0	@	0.0533250	$21.76
Res. Deferred Supply	911.0	@	0.0008010	$0.73
Total Market Purchased Electric Supply Charges				**$47.91**

Residential Supply and T&D bills 1998-2007
Based on 750 KWh monthly consumption
(July 2007 is estimated)

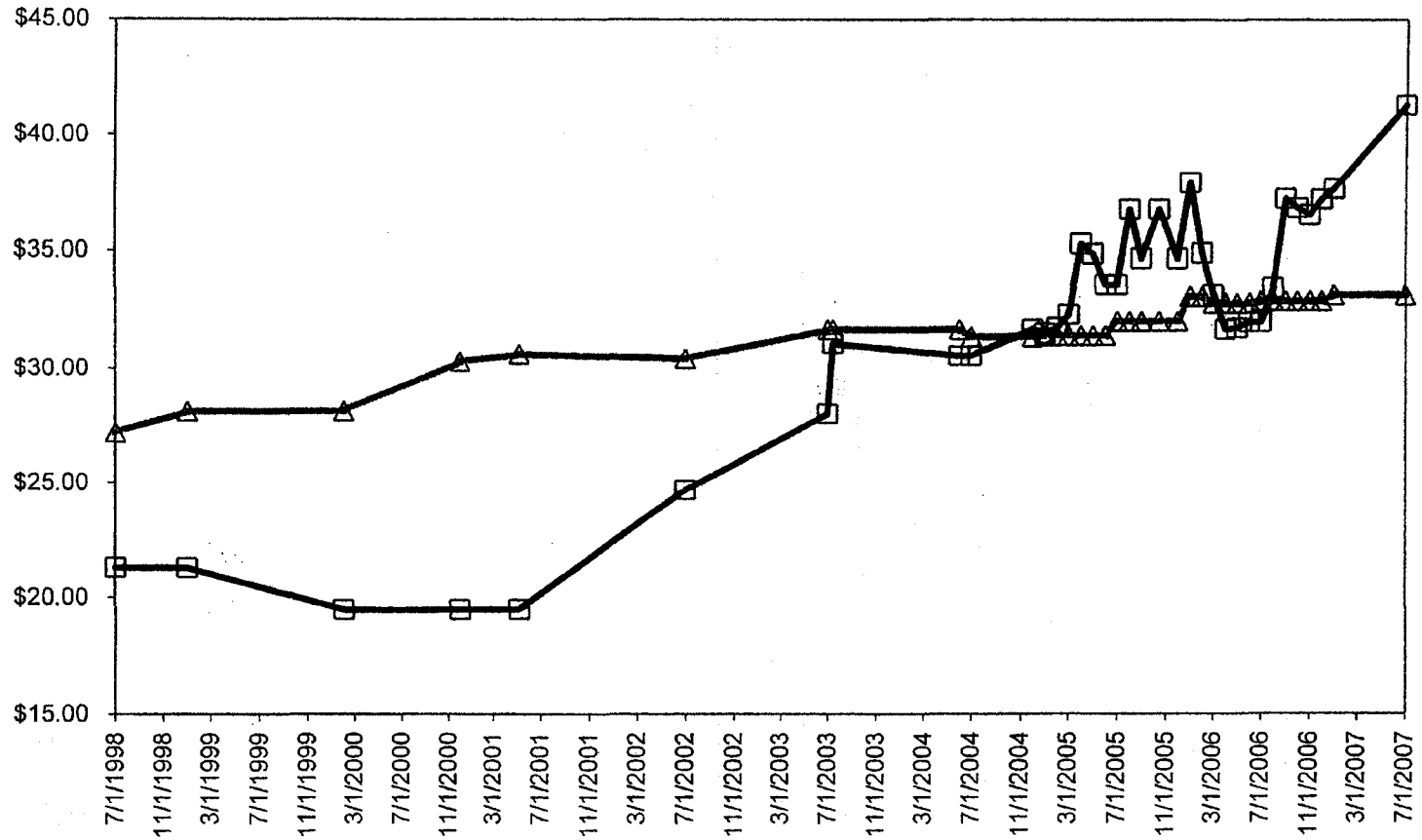


EXHIBIT NO. 11
DATE 3-30-07
HB 25

Bob Raney
3/30/07
222-0558

Northwest Energy Transmission and Distribution (Regulated) compared with
Northwest Energy Default Supply (Unregulated)

	Supply	T&D	Total
Jul-98	$ 21.30	$ 27.20	$ 48.50
Jan-99	$ 21.30	$ 28.14	$ 49.44
Feb-00	$ 19.48	$ 28.14	$ 47.62
Dec-00	$ 19.48	$ 30.29	$ 49.77
May-01	$ 19.48	$ 30.61	$ 50.09
Jul-02	$ 24.67	$ 30.41	$ 55.08
Jul-03	$ 28.02	$ 31.67	$ 59.69
Jul-03	$ 31.07	$ 31.67	$ 62.74
Jun-04	$ 30.53	$ 31.67	$ 62.20
Jul-04	$ 30.53	$ 31.35	$ 61.88
Dec-04	$ 31.68	$ 31.35	$ 63.03
Jan-05	$ 31.50	$ 31.41	$ 62.91
Feb-05	$ 31.75	$ 31.41	$ 63.16
Mar-05	$ 32.31	$ 31.41	$ 63.72
Apr-05	$ 35.28	$ 31.41	$ 66.69
May-05	$ 34.87	$ 31.41	$ 66.28
Jun-05	$ 33.57	$ 31.41	$ 64.98
Jul-05	$ 33.57	$ 32.02	$ 65.59
Aug-05	$ 36.75	$ 32.02	$ 68.77
Sep-05	$ 34.66	$ 32.02	$ 66.68
Oct-05	$ 36.75	$ 32.02	$ 68.77
Dec-05	$ 34.66	$ 32.02	$ 66.68
Jan-06	$ 37.89	$ 33.09	$ 70.98
Feb-06	$ 34.89	$ 33.09	$ 67.98
Mar-06	$ 33.15	$ 32.78	$ 65.93
Apr-06	$ 31.65	$ 32.78	$ 64.43
May-06	$ 31.72	$ 32.78	$ 64.50
Jun-06	$ 31.97	$ 32.78	$ 64.75
Jul-06	$ 31.97	$ 32.89	$ 64.86
Aug-06	$ 33.45	$ 32.89	$ 66.34
Sep-06	$ 37.20	$ 32.89	$ 70.09
Oct-06	$ 36.80	$ 32.89	$ 69.69
Nov-06	$ 36.51	$ 32.89	$ 69.40
Dec-06	$ 37.18	$ 32.89	$ 70.07
Jan-07	$ 37.63	$ 33.15	$ 70.78
Jul-07	$ 41.25	$ 33.15	$ 74.40
%change	94%	22%	53%

MONTANA POWER COMPANY - 1997

"Vertically Integrated" electricity and gas utility
It owns/operates hydro and thermal generators, gas fields, and gas and electric transmission and distribution lines.
It is fully ***REGULATED***

Company divided into two separate operations

REGULATED
MPC generation and gas field assets

REGULATED
MPC transmission and distribution assests

1997 de-regulation occurs

NOT REGULATED
PPL MT buys electric generators
International companies buy gas fields

REGULATED
NWE buys transmission and distribution assets. Cannot own generation (except for Colstrip assets)

REGULATION proposed in legislature
2007 discussion on "re-regulating" NWE
~~NWE would be allowed to own generation again~~
and become "vertically integrated"
NWE generators would be PSC regulated along with electric transmission and distribution assets

Reregulation would not affect natural gas fields and gas production

Bob Raney
222-0558
3/30/07

EXHIBIT NO. 12
DATE 3-30-07
SB. NO. HB 25

Mood, Doug

From: Brogan, Al
Sent: Tuesday, March 27, 2007 10:56 AM
To: PSC_Electric
Attachments: Brogan, Al.vcf

Interesting op-ed re electricity deregulation. The court case referred to is *Colorado Office of Consumer Counsel v. FERC*, Case No. 04-1238 (DC Circuit). The court heard oral argument on 3/14/2007

Opinion > op/ed

Is deregulation of electricity illegal?

BY MARJORIE KELLY AND RICHARD ROSEN

ORIGINALLY PUBLISHED MARCH 27, 2007

When economic orthodoxy trumps the public good and violates due process along the way, we're in deep trouble. That is precisely what has happened with the nation's misguided experiment in electricity deregulation, which led to the furor in Maryland and other states over electricity prices spiraling out of control, leaving consumers struggling to pay bills 50 percent to 100 percent higher than in recent years.

If we trace the long road of electricity deregulation to its source, we find the main culprit is the Federal Energy Regulatory Commission (FERC). For nearly two decades, this little-known executive agency has been stealthily undermining the consumer-friendly electricity regulatory framework built during the New Deal.

The problem dates to the era of President George H. W. Bush in the late 1980s, when FERC first allowed a utility company to charge market prices for wholesale power. Avoiding the sunlight of public rule-making, FERC over the years relied upon case-by-case decisions as it gradually shifted much regulatory authority from the settled practice of cost-of-service regulation toward a new market-based framework.

In the process, state utility commissions lost power. The executive branch of the federal government gained power. The public lost out. And the whole process was illegal, according to the attorneys general of Rhode Island, New Mexico, Colorado and Utah, who this month argued their path-breaking case before a federal appeals court in Washington.

Enraptured with market fundamentalism - spread by Enron Corp. lobbying - more than a dozen states, including Maryland, took further steps toward deregulated electricity in the 1990s. This massive experiment is now more than a decade old, and the results can be summed up in a word: disaster. As a recent Tellus Institute study shows, consumers in deregulated states in 2006 paid 55 percent more for electric power than those in regulated states - leaving some residents to choose between staying warm and paying for medicine and food. Further increases have yet to show up in many states, including Maryland, Connecticut and Delaware, where price caps and phase-ins have delayed the problem. Some states now are struggling to undo the mess of deregulation.

"The last time we relied on the market to set electricity prices, it was the Great Depression," and the

chaos that followed led to the Federal Power Act of 1935, says Lynn Hargis, a former FERC staffer who is now an energy attorney with Public Citizen.

It is at our peril that we forget the lessons of the Depression: that certain kinds of markets, left to their own devices, can create havoc. Yet what is at work here is not just misguided ideology. In the case heard this month by the federal appeals court for the D.C. Circuit, the four states - represented by Ms. Hargis - argued that in its switch to market-based pricing, FERC violated the Federal Power Act, which requires the agency to see that electricity prices are "just and reasonable."

In short, FERC has been acting illegally. Operating out of a near-religious faith in markets, the commission stripped authority from state utility commissions, which for decades had successfully overseen electricity rates. FERC instead handed electricity price-setting over to markets. And it did so in a way that subverted congressional authority and due process. With their case, the four states aim to return wholesale electricity rate-setting to a cost-of-service basis, thereby restoring vital consumer protections.

This issue relates to a broader stealth attack on the New Deal. And it is part of a larger attempt to have markets take over critical public services such as water, prisons, education and electricity.

The slow-motion disaster of electricity deregulation - and FERC's illegal actions permitting it - can serve as a vital wake-up call. We must remember that public services such as electricity are not commodities but public goods, necessities of life essential to the well-being of all, and thus must be subject to public oversight - not left to markets.

Marjorie Kelly, for 20 years editor of Business Ethics magazine, is senior associate at the Tellus Institute. Her e-mail is mkelly@tellus.org. Richard Rosen, for 30 years a consultant to public utility commissions, is a senior fellow at Tellus. His e-mail is rrosen@tellus.org.

Al Brogan
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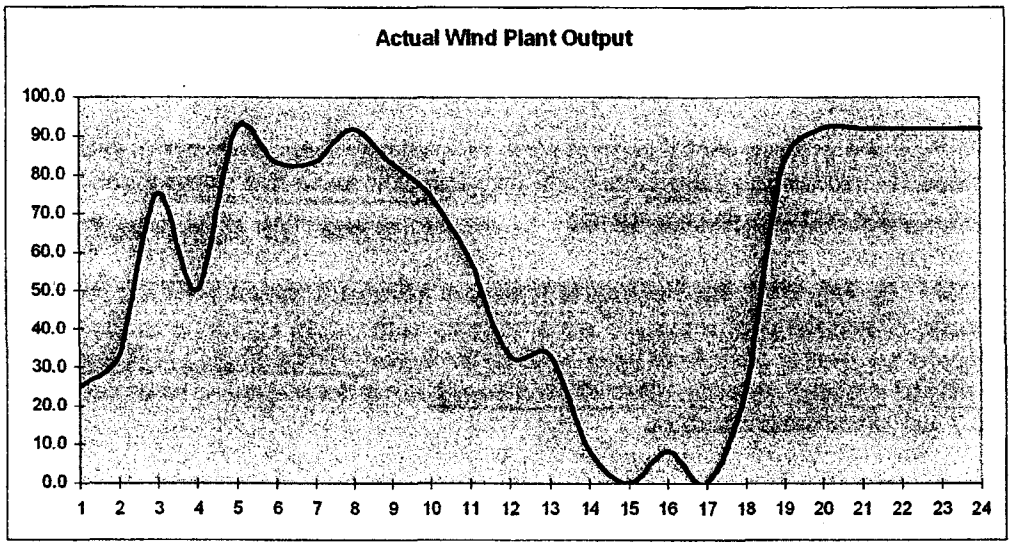
BPA (1)

Figure 4: Illustrative diurnal output of a wind plant



Wind integration in the within-hour time frame

Wind increases the demand for additional regulating (several second response time) and load following (several minute response time) reserves in the within-hour time frame. Control areas carry regulating reserves to manage the minute-to-minute changes in their load and resource balance. Northwest control areas also carry load following reserves to maintain system balance across the remainder of the scheduling period (60 minutes in the Northwest). Regulation and load following reserves are types of operating reserves. Other types of operating reserve include contingency reserves for responding to sudden unplanned generation or transmission[10] outages.

Figure 5 illustrates the combined within-hour behavior of 208 MW of installed capacity from four wind projects in the BPA system. The figure depicts the probability distribution of wind output changes, as megawatts up or down, over the 1-minute, 10-minute and 60-minute time horizons. As can be seen, for all three series, the variability is clustered around zero with low probabilities of occurrence in the tails of the distributions.

[10] Under current rules, wind projects are treated like hydro resources from the perspective of contingency reserves.

deploying additional sources of flexibility. This is evidenced in other regions of the country such as Colorado and Texas that depend primarily on gas turbines to provide wind integration services. As a result, based on the initial results in Table 4 and the fact that only six of the 16 Northwest control areas are represented in the results, there do not appear to be any fundamental technical barriers to integrating 6,000 MW of wind in the Northwest. It's a question of at what cost.

Cost estimates

Table 5 presents the preliminary cost estimates expressed in $/MWh of wind generation by increasing amount of wind penetration (nameplate wind/peak load).

Table 5: Preliminary wind integration costs from initial utility studies ($/MWh of wind generation)[13]

Utility	Peak Load (MW)	5%	10%	20%	30%
Avista	2,200	$2.75	$6.99	$6.65	$8.84
Idaho Power	3,100		$9.75	$11.72	$16.16
Puget Sound Energy	4,650	$3.73	$4.06		
PacifiCorp	9,400	$1.86	$3.19	$5.94	

Utility	Peak Load (MW)	5%	10%	20%	30%
BPA (Within-Hour Impacts Only)	9,090	$1.90	$2.40	$3.70	$4.60

NorthWestern Energy has reported to the Montana Public Service Commission a wind integration cost of $6.75/MWh for the Judith Gap project for 2006. This value is yet to include the expenses for the operation of the Basin Creek gas-fired plant that are solely attributable to wind integration. The wind integration costs for Basin Creek have not been finalized for 2006. The NorthWestern control area has a wind penetration of 8.7 percent and is currently purchasing all of its control area services at market-based rates.

Key findings

Based on Northwest studies and others from around the world, the cost of wind integration is largely dependent on: (1) the size of the control area where such services are procured in relation to the amount of wind being integrated; (2) the geographic diversity[14] of wind sites and resultant generation patterns; (3) the amount of flexibility available to the power system, and (4) access to robust markets for control area services and storage and shaping products.

Table 5 illustrates a general trend of lower wind integration costs with increasing control area size. The Avista numbers also shine light on the benefits of geographical diversification. By virtue of purchasing a more geographically diverse portfolio of wind projects under its 20

[13] BPA evaluated the current amount of wind in its system (733 MW) and then evaluated costs at 1000 MW (11 percent penetration), 2000 MW (22 percent) and 3000 MW (33 percent). For ease of comparison, the percentage figures have been rounded down slightly in Tables 5 and 6.

[14] Diversity in this context refers to the extent to which changes in wind output at one wind site are different from the changes at other wind sites.

(3)

percent penetration case relative to its 10 percent case, Avista is able to double the amount of wind in its system while simultaneously lowering its per-megawatt hour costs.

Wind integration costs are also driven by dynamic market variables and the amount of system flexibility available to each utility. For hydro-dependent utilities that provide flexibility from their own resources, wind integration costs are largely a function of the spread between peak and off-peak power prices, and current water supply conditions. For control areas with insufficient flexibility to manage their own wind resources, wind integration costs are a function of the market price for control area services and other required shaping products. Absent access to other sources of flexibility, utilities will need to invest in new generating or demand-side resources to secure the needed flexibility.

read NWE + Gas fired Electric

Several of the studies also found that integration costs were very sensitive to the absolute level of wholesale energy market prices. Where market prices rise or fall by 50 percent from today's levels, integration costs would also be expected to change by a similar percentage. **Table 6** expresses the individual utility wind integration costs as a percent of the wholesale price of electricity embedded in each of the studies.

Table 6: Preliminary wind integration costs from initial utility studies expressed as a percent of wholesale electricity market prices

Utility	Peak Load (MW)	5%	10%	20%	30%
Avista	2,200	5.0%	12.7%	12.1%	16.1%
Idaho Power	3,100		15.5%	18.7%	25.8%
Puget Sound Energy	4,650	6.2%	6.8%		
PacifiCorp	9,400	3.1%	5.3%	9.9%	

Utility	Peak Load (MW)	5%	10%	20%	30%
BPA (Within-Hour Impacts Only)	9,090	3.2%	4.0%	6.2%	7.7%

Using Table 6, it is possible to estimate wind integration costs at various levels of wind penetration and market prices and to normalize the wind integration cost estimates of individual studies that may have been based on different electricity market prices.

The Northwest wind integration supply curve

Conceptually, regional wind integration costs can be represented as a supply curve relating cost to the level of installed wind capacity. The incremental costs start out very low, as the amount of variability introduced by a small amount of wind is virtually lost in the larger fluctuations of loads. As the amount of wind increases, the effects of wind variability ultimately dominate, and flexibility needs to be added to the system in direct proportion to the growing wind penetration. Some analysts suggest that there is an upper limit on how high wind integration costs can go based on the cost of gas-fired resources. Consider a combination of a wind project and a gas turbine, each with the same nameplate capacity. The two projects are operated to meet a fixed contractual amount equal to their individual nameplate capacity – the wind project serving to offset the gas resource when the wind blows. For example, a 300 MW wind farm could

utilities will share Area Control Error (ACE), which may reduce the amount of regulating reserves each of the individual utilities must carry. Though the incremental demand for regulating reserves from wind energy is quite small, if successful, ADI may take a small bite out of the costs of wind integration as well.

The participating utilities have demonstrated an admirable spirit of cooperation and dedication to solving the technical issues associated with ACE Diversity Interchange. To create greater awareness of this initiative, in July 2007, the participants in the ACE Diversity Interchange pilot should provide a progress report to the Steering Committee of the Northwest Wind Integration Forum.

ACTION 12: By July 2007, the participants in the ACE Diversity Interchange pilot should provide a progress report to the Steering Committee of the Northwest Wind Integration Forum.

Expanded markets for flexibility services

Lessons learned from the ACE Diversity initiative may help expand the availability of other control area balancing services that can effectively pool system flexibility beyond the minute-to-minute time horizon of regulation. This is an important objective. As discussed in Section I, the variability of wind (and control area operations in general) is larger across the 10-minute to 60-minute time horizon than it is across the regulation time horizon. Wind variability in this timeframe is responsible for a majority of wind integration costs and therefore represents the greatest area for potential cost savings.

Services designed to provide additional flexibility across the within-hour time horizon include Supplemental Automatic Generation Control (AGC) and Dynamic Scheduling. These products and their variants allow one utility to take on a portion of the within-hour balancing requirements for another utility's control area.

Through the provision of Supplemental AGC, one entity (control area operator or independent power producer) sells a contractually defined amount of generation flexibility (either unidirectional or bi-directional) to assist a control area in managing its within-hour system variability. Dynamic Scheduling effectively moves the output of a load or generating resource from one control area to another. Other products, such as storage and shaping services, can help manage hour-to-hour wind variability.

The market for control area services and storage and shaping products is very limited. NorthWestern Energy knows this from direct experience. In an effort to purchase additional control area services to manage the 135 MW Judith Gap wind project, NorthWestern has run several solicitation processes and found a very small number of sellers. In 2005, BPA placed a moratorium on the sale of its wind integration services, and Grant County PUD is not offering storage and shaping services to new customers.

The Technical Work Group explored the root causes of the limited activity in the market for flexibility services, and identified several important barriers:

1) There are no formal markets or standard product descriptions for wind integration services;

Glossary

ACE, Area Control Error: A measure (in MW) of the moment-to-moment load resource balance within a control area. Technically, ACE measures the instantaneous difference in scheduled and actual system frequency and a Control Area's scheduled and actual interchanges with other control areas.

ADI, ACE Diversity Interchange: Coordination among multiple control areas to relax the control needed to balance load, interchange, and generation compared with isolated operations. Relaxed control can be achieved because of the sign diversity (some are net positive or over-generating relative to load and some are net negative or under-generating relative to load) among area control errors of the participating control areas.

AGC, Automatic Generation Control: Generation equipment that automatically responds to changes in system frequency in order to maintain target system frequency (60 cycles per second in the US) and/or the established interchange with other control areas within predetermined limits.

ATC, Available Transmission capacity: The amount of marketable transmission capacity on a defined transmission path after accounting for existing contractual obligations and operating margins.

Busbar: The point at which power from a generating resource is first delivered to the high voltage grid. Busbar costs are calculated before considering the costs of transmitting power to load.

Capacity Factor: A measure of the actual annual energy output of a generating resource divided by the theoretical maximum output, if the machine were running at its rated capacity during all 8760 hours of a year.

Capacity Value: A measure of the amount of additional peak load that can be served by a generating resource without a degradation in system reliability. For example, a 100 MW wind project with a demonstrated 15 percent capacity value could reliably serve an additional 15 MW of peak load.

Control Area: An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the Interconnection. (Also referred to as "Balancing Area" or Balancing Authority").

CPS, Control Performance Standard: A metric used by the North American Electric Reliability Council (NERC) to evaluate the performance of control areas. CPS2 requires that 95 percent of imbalances between generation and load above a certain threshold be rectified within 10 minutes.

Dynamic Performance: The extent to which a generating resource or other element can help support grid stability during periods of system disturbance such as a voltage drop.

Flow Gate: A point in the transmission system defined as a grouping of one or more transmission lines, used to measure power flow, usually defined when there is limited capacity across a portion of the transmission system.

LGIA, Large Generator Interconnection Agreement: The Federal Energy Regulatory Commission's standardized interconnection agreement for generating resources greater than 20 MW that proscribes a

process for review of interconnection requests and a standard contract format. Created by FERC Order 2003A.

Load Following: The deployment of flexible generating resources (or demand-side options) to adjust to changes in loads across the 10-60 minute and longer time horizon. Load following is not technically a type of operating reserve, but as a within-hour service, it is provided between system basepoint adjustments and therefore requires capacity to be reserved from the marketplace given the block-hourly markets in place in the Northwest.

OATT, Open Access Transmission Tariff: The Federal Energy Regulatory Commission Tariff defining the requirements for the provision of non-discriminatory wholesale electrical transmission service.

Operating Reserves: As defined by WECC, the sum of Regulation reserves and Contingency reserves, both spinning and non-spinning, As used in this report, operating reserves include the generation capacity needed to follow moment-to-moment changes in loads and wind (regulation) and longer-term (10-60 minute) changes in loads and wind (load following). As used in this report, operating reserves do not include capacity used to shape the output of wind projects over diurnal or seasonal periods.

OTC, Operating Transmission Capacity: The total transmission capacity of a line or group of lines (flow gate) after setting aside a margin for reliability and non-contract flows.

POS, Plan of Service: An engineering and economic assessment of the physical infrastructure required to interconnect a new resource to the grid or to increase the transfer capacity across a portion of the transmission system.

RAS, Remedial Action Schemes: Protective systems that ensure that corrective actions take place immediately following the forced outage of a transmission line or transmission system element.

Renewable trunk line transmission: A radial transmission line primarily intended to serve multiple renewable resource projects located within a common resource area.

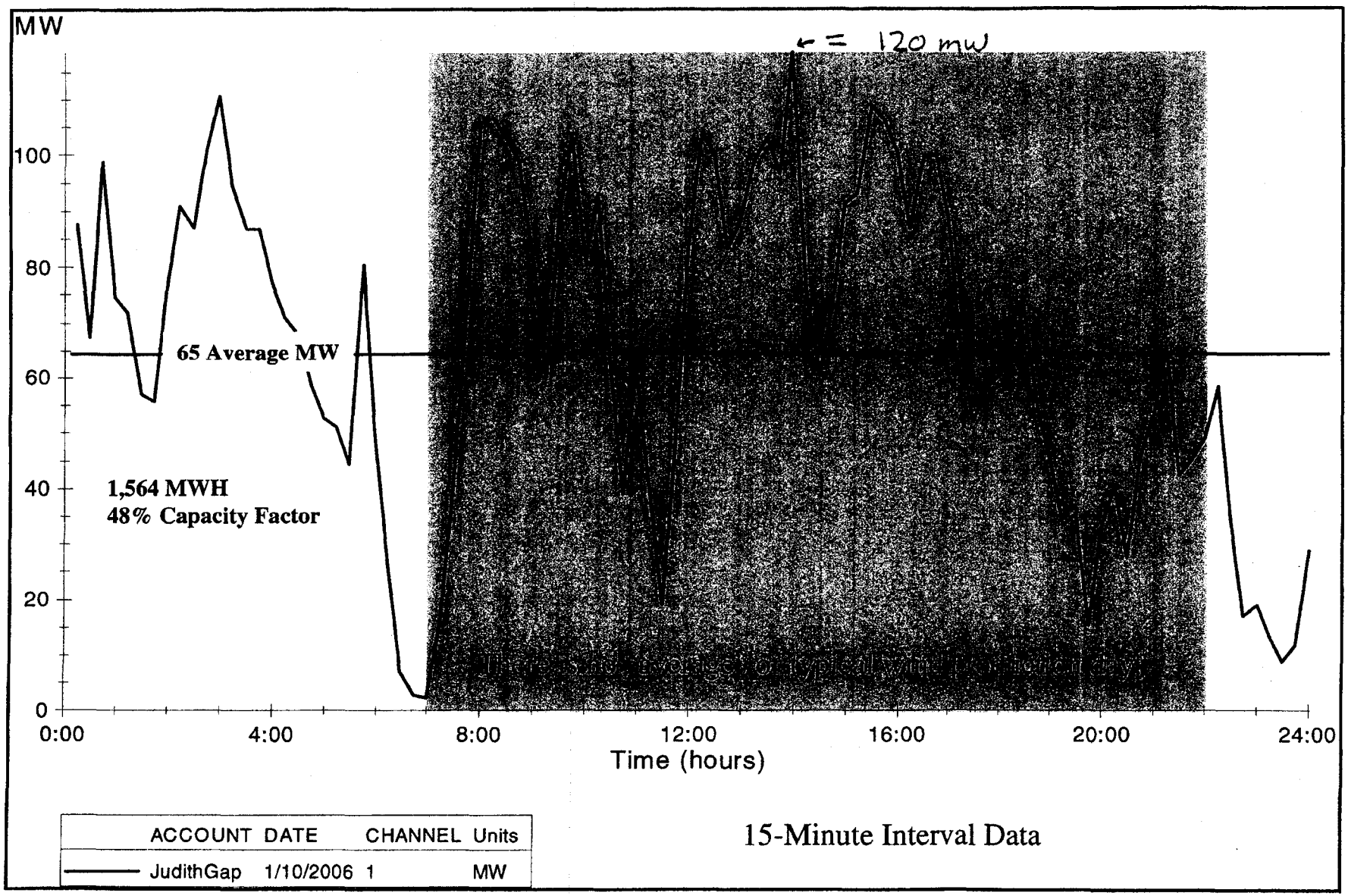
Storage and shaping: The practice of converting the variable hourly output of a resource like wind energy into predictable volumes of power for later delivery, sometimes shaped into flat blocks of peak and off-peak energy.

System flexibility: The ability of both supply-side and demand-side resources to respond to changes and uncertainties in system conditions. Flexibility also refers to the ability of the hydro system to store water for delivery in future time periods.

Regulation: The deployment of fast, responsive generating capacity to manage moment-to-moment changes in the load resource balance of a control area. Regulation is usually provided by units on Automatic Generation Control (AGC).

PEAKED 7 times NWE (1)

Variation + 20 mw 16 times



What have we done?

NWE <u>Default Supply</u> purchased Regulating Reserves and made them available to the Transmission Operator/Control Area Operator

- Historical Transmission Customer Resource (before wind integration)
  - Idaho Power – 60 MW (± 30 MW)
  - Base price $2.7 million / year

Wind Integration

- New Regulating Resource from Avista Corp
  - Purchased at the beginning of 2006
  - 15 MW (± 7.5 MW): ~11% of default supply wind resource
  - Base price: $1.1 million / year:
- Second Purchase from Avista
  - Added in June to correct CPS2 performance
  - 10 MW (± 5 MW)
  - Base price: $740,000 / year
- Regulating reserves to support the new wind generation
  - 25 MW ~18% of default supply wind resource
  - Nearly $1.8 million/year
- Costs are increasing for this product…

EXHIBIT NO. 13
DATE 3-30-07
SB HB 25

Testimony in Support of HB 25
To the Senate Natural Resources and Energy Committee
March 30, 2007

543-0026

Chairman Lind, members of the Committee, my name is Gerald Mueller. I testify in support of HB 25 as a customer of NorthWestern Energy, but not on behalf of NWE or any other agency or organization. As I have previously emailed you, I have facilitated NWE's Electricity Technical Advisory Committee since its inception in 2002, so I am familiar with NWE's electricity resource planning and portfolio. A summary of my experience with electricity utilities in Montana and the Pacific Northwest is attached to this testimony.

In my judgement, HB 25 is one of the most important energy bills that this Committee will consider this session. If passed, it will establish a framework that will allow us to begin to recover from the damage caused by the Montana's disastrous experiment with electricity restructuring.

The restructuring damage was caused by the separation of MPC's customers, now NWE's default supply customers, from the generation resources built to serve them, the dams on the Missouri, Flathead, and Clark Fork Rivers, and the coal plants at Billings and Colstrip. This separation meant that the default supply customer had to be served via purchases from the wholesale power market. This market has not served NWE customers well. The market price of electricity has been and will continue to be much higher than the electricity produced by MPC's former dams and coal plants.

The key provisions of HB 25 are as follows:

- Section 7 ends customer choice and stabilizes NWE's customer base.
- Section 14, 69-8-421(7) authorizes NWE to make investments in electricity generation through building or by purchasing equity positions in new generation, and directs the Montana Public Service Commission (PSC) to provide rate recovery for resources that it approves.
- Sections 12 and 13 subject utility planning to guidance from PSC.
- Section 14, 69-8-421(1) allows a utility to seek PSC approval of electricity resources before the utility acquires them.
- Section 14, 69-8-421(8) states that this approval does not limit the ability of PSC subsequently to prevent rate recovery of costs that result from the utility's failure to "...to reasonably manage, dispatch, operate, maintain, or administer new electricity supply resources."

These provisions will allow NWE to make long-term equity investments in generation resources dedicated to serve its customers.

To make long-term equity investments, a utility must have a reasonable likelihood that it will recover them. A reasonable likelihood, in turn, is dependent on a stable customer base and the inclusion of the generation resource investments in rate base. As the preceding recitation of the bill provisions demonstrates, HB 25 provides for both in a manner that allows the PSC to protect customer interests. The PSC would guide utility resource planning and remain in control of what resource costs go into the rate base. If so requested, the PSC could approve a generation resource before the utility invests tens to hundreds of millions to billions of dollars in it. This pre-acquisition approval both will allow the PSC to apply public policy issues inherent in

resource acquisitions to a specific resource decision before the utility invests in it and will likely reduce the utility's cost to finance the investment.

Examples of public policy issues that should be made by the elected PSC and not the utility include:

- How much long-term resource "insurance" the utility should buy to protect customers against rate spikes;
- Whether and how the utility should favor resources such as conservation and renewables, whether and how potential regulatory changes such as carbon dioxide emission limitations should be addressed; and
- How much system reliability is enough.

The pre-acquisition approval would all but eliminate the risk that the PSC would subsequently disallow rate recovery for the utility's entire resource investment which would lower financing costs. The savings from the reduced risk and lower financing costs could and should be passed to customers, lowering their energy costs.

HB 25 clearly provides that the pre-acquisition approval does not limit the PSC from excluding costs from the rate base arising from the utility's failure to reasonably control resource construction costs and efficiently run and maintain its system.

There are no easy, quick fixes to the situation we find ourselves in due to restructuring. The low, pre-restructuring electricity rates are gone, and they are not coming back.

NWE customers now need a way to get out of the total reliance on the wholesale power market. They need the protection afforded by the PSC and the Montana Consumer Counsel in doing so. HB 25 provides both the way and the protection.

I urge you to vote to approve this bill.

Thank you.

Electric Utility-Related Experience of Gerald Mueller

Montana State Government

3/74 - 1/78	Air Analyst, Energy Planning Division, Montana Department of Natural Resources and Conservation
1/78 - 5/78	Program Manager, Major Facility Siting Act, Energy Planning Division, Montana Department of Natural Resources and Conservation
5/78 - 1/81	Administrative Assistant and Energy Advisor to the Lt. Governor of Montana, Ted Schwinden
1/81 - 4/81	Administrative Assistant and Energy Advisor to the Governor of Montana, Ted Schwinden
4/81 - 1/88	Montana Member, Northwest Power Planning Council

Energy and Natural Resource Consultant

NorthWestern Energy

- Facilitated Electricity Technical Advisory Committee (2002 to present).
- Facilitated Natural Gas Technical Advisory Committee (2004 to 2005).
- Facilitated Universal System Benefits Advisory Committee (2002 to 2004).

The Montana Power Company

- Facilitated Universal System Benefits Advisory Committee (1999 - 2001).
- Facilitated Conservation and Least Cost Planning Advisory Committee (1988 to 1998).
- Facilitated Collaborative on Customer Education and Pilot Programs (1997).
- Facilitated Free Weatherization Collaborative (1994).

The Western Montana Generation and Transmission Cooperative

- Strategic planning for the WMG&T Board of Directors (1998).
- Small Customer Buying Cooperative (1998).

Fergus Electric Co-op

- Strategic planning for the Co-op Board of Directors and management staff (2002).

Glacier Electric Co-op

- Strategic planning for the Co-op Board of Directors and management staff (2002).

Missoula Electric Co-op

- Strategic planning for the Co-op Board of Directors and management staff (2002).

Ravalli County Electric Co-op

- Strategic planning for the Co-op Board of Directors and management staff (1998, 2002, and 2004).

The Bonneville Power Administration

- Meeting facilitation, including meetings between the BPA administrator and staff and the four Pacific Northwest state public utility commissions and a four state teleconference concerning electricity restructuring (1997 to present).

Montana Human Resources Council Directors' Association

- Testified in an MPC rate case as an advocate of low-income weatherization.

EXHIBIT NO. 14
DATE 3-30-07
SB NO. HB25

NorthWestern Energy
Electric Residential
Rates by Tran/Distr. & Supply

	Cents per kWh	
Year	**Tran/Distr**	**Supply**
2001	$ 0.040813	$ 0.025973
2002	$ 0.038447	$ 0.031667
2003	$ 0.039153	$ 0.038400
2004	$ 0.042047	$ 0.040386
2005	$ 0.042287	$ 0.045381
2006	$ 0.043849	$ 0.046042
2007	$ 0.044769	$ 0.051876
2008	$ 0.045053	$ 0.055180

Prepared by:
NorthWestern Energy
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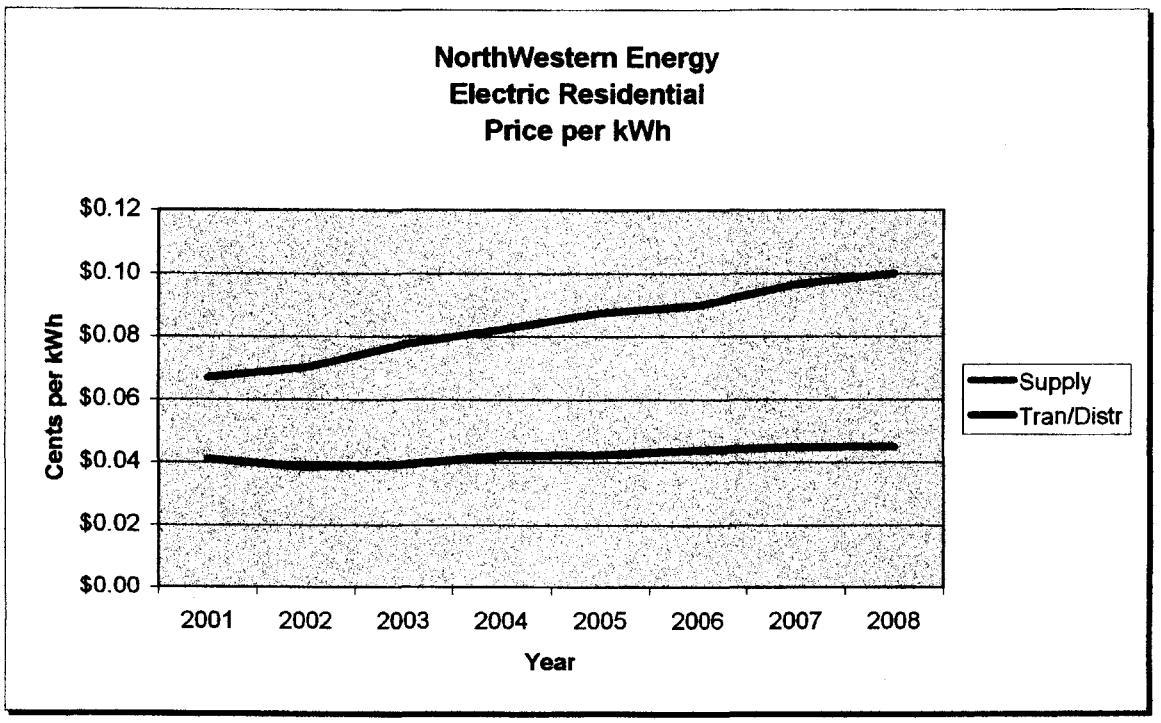
Helena, MT 59601
(406) 449-9819



Transmission and distribution (T&D) rates have not been adjusted since MPSC issued Final Order 6271c in May 2001. The T&D rate adjustment was based on a 1999 test year. The only rate adjustments that have occurred after is related to the incremental property tax adjustment allowed by Montana law. Electric utility property taxes represent approximately 17% to 21% of the T&D rate. All of the increase in the T&D rates since 2004 has been caused by increases in property taxes.

The primary supply costs are paid directly to PPL of Montana.

EXHIBIT NO. 15
DATE 3-30-07
SUB NO. HB 25

Testimony of Ken Toole in opposition to HB 25

Members of the committee, I apologize for not being able to offer testimony in person. I have asked to have a brief statement read because I am the only Public Service Commissioner opposed to this bill because of its provision allowing pre-approval.

I do not believe, nor do most consumer advocates in Montana, NorthWestern Energy needs to have "pre-approval" in order to build new generation facilities. Currently plants are being built is states with out pre-approval. More over, it now appears that in Montana at least one plant in Great Falls, the former 1st Megawatts proposal, will be built without pre-approval. Finally, it is important to note that utilities have always argued that they need pre-approval to build plants. There is nothing new in the arguments we now hear.

The following are some of my concerns about the bills currently in the legislature to allow Northwestern Energy to own power generating plants. Clearly, it would be beneficial to "re-regulate" Northwest Energy but it should be done in a way that protects the public interest.

Pre-approval shifts risk from investors to consumers- Pre-approval asks the Public Service Commission to allow the utility to recover costs regardless of whether the plant is actually needed when it is put into service. There is also risk that the market price drops and the pre-approved plant price is much higher. This happened all over the country in the mid-1980s. With pre-approval rate payers will be on the hook regardless of the market price and regardless of whether the plant is needed.

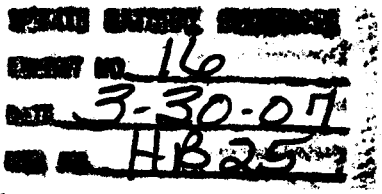
Pre-approval is opposed by consumer advocates- The Montana Consumer Council and other consumer advocates in Montana have always opposed pre-approval because it shifts market risk to consumers. Call the Montana Consumer Counsel, Bob Nelson at 444-2771.

Pre-approval is not common in other states' regulatory regimes- While there are some states with differing forms of pre-approval, it is not the norm. Based on a few phone calls to western states I can tell you that Wyoming does not allow pre-approval, Arizona does not allow pre-approval, Oregon does not allow pre-approval and Nevada does not allow pre-approval.

Granting pre-approval is an over-reaction to temporary market conditions- Pre-approval advocates argue that nothing will get built without pre-approval. The deregulated merchant power market has collapsed. There is currently a lot of uncertainty in power markets. This condition is temporary (as we have seen before). Markets will likely get more stable and financing for new plants will be more available in private markets.

Granting pre-approval will lead to poor decision making- Risk leads to conservative decision making. Shifting risk away from investors to rate payers makes the utility less vested in good decision making.

Just like Chicken Little, utilities have always predicted dire consequences if they were not granted pre-approval. Following the bond defaults and overbuilding of the early 80's utilities made the exact same arguments we hear today. The sky did not fall then and it won't now.



Statement of PPL Montana
Before the Natural Resources and Energy Committee
Of the Montana State Senate
Regarding House Bill No. 25
March 30, 2007

David Hoffman, Manager, External Affairs
825 Great Northern Blvd.
Helena, Montana 59601
(406) 457-5300

Mr. Chairman and members of the Committee:

My name is David Hoffman, Manager of External Affairs for PPL Montana.

House Bill 25 is a very complicated bill that represents major policy shifts that are easily identifiable, on the one hand, and not easily identifiable, on the other.

The bill is touted as a "re-regulation bill" that would allow the regulated utility, NorthWestern Energy, to re-integrate into its customer rate base generation assets it chooses to build, buy or lease. It also allows the PSC to "pre-approve" projects the utility brings before it, and it eliminates all customer choice except those customers who currently exercise choice and choose to remain at market. After pre-approval, NorthWestern would then be able to charge customers for all the costs of such generating assets, whether those costs were prudent or imprudent. Other consequences, perhaps unintended, that this sweeping piece of legislation may create which adversely impact Montanans are unknown.

In addition to the almost total elimination of customer choice, there are several other issues to consider:

1. **It adopts for the first time in Montana history a desperate regulatory policy of pre-approval, and with it the potential disaster of shifting risk of unforeseen costs onto the consumer. Building new generation is costly and can involve significant cost increases and cost overruns. Environmental costs and construction costs have increased significantly and will likely continue to increase. Pre-approval gives NorthWestern a "blank check," and places the risk of these cost increases and overruns on ratepayers and insulates NorthWestern from any risk whatsoever for any cost increases or overruns;**

2. **There is no urgency to act now on a bill that so dramatically alters Montana's utility laws. NorthWestern has already contracted for a vast**

majority of its electricity supply needs well into the future, from a variety of suppliers;

3. House Bill 25 will increase, not decrease, costs for electric consumers in Montana. Montanans know that government regulation of industry will likely increase, not decrease, costs for consumers rate base.

4. The process of moving this bill closely parallels SB 390, passed in 1997, that was primarily written by the utility and which moved through the legislature with split PSC support, massive lobbying efforts by MPC, tons of amendments that very few people could explain, and numerous unintended and adverse consequences. For example, this bill was heavily amended (77 amendments in a single motion, among others) in the House Federal Relations, Energy and Telecommunications Committee, without adequate time to review and understand the purpose of such amendments; and

5. The future of NorthWestern Energy is a mystery. It has submitted a proposal to the PSC for acquisition by an Australian investment firm. We do not know what this utility will look like twelve months from now, let alone five years from now.

Interestingly, in this debate PPL Montana has been held up as a villain by NorthWestern and certain of PSC Commissioners, and PPL is cited as one of the main reasons this bill is needed. They claim that PPL Montana has a monopoly on supply available to NorthWestern, and that price increases have been unreasonable—and further, this bill will fix the perceived problem.

These monopoly claims are wrong and have been rejected flatly by the appropriate government agency. Also, NorthWestern has conducted several procurements for supply, where they touted the large number of bidders and robust competition they experienced. In a publication on the NorthWestern website posted last July, NorthWestern touted the new 7-year contract with PPL Montana as being very positive for Montana consumers. This publication defends the contract, which provides about one-third of its supply, as providing "rate certainty and stability" for customers. Further, NorthWestern claims the PPL contract represents a "significant discount to forward market prices" and provides NorthWestern with the "flexibility to diversify."

Now, a mere six months later, NorthWestern is trying to take a completely different position. But that shouldn't be surprising, in light of a recent commentary in the Billings Gazette where NorthWestern's Chairman wrote "We've said it before, and we'll say it again, our current shareholders do not have Montana consumers' interests at heart."

Adoption of the major changes to the electricity laws in HB 25 calls for a cautious and considered approach. For the sake of all Montanans and our state's economy, we must be sure that any changes create economic benefit. Simply allowing the return to cost-of-service regulation will not create corresponding lower supply prices, and everyone agrees it would not mean a return to conditions that existed before 1997.

Throwing out customer choice and electric competition in favor of traditional cost-of-service regulation through HB 25 is not the answer. If you truly want to act to promote the lowest cost supply of electricity for consumers, you should act to expand – not eliminate – retail customer choice and help to spur a more vibrant, competitive retail market. Vibrant competitive retail markets, along with the already vibrant and competitive wholesale markets, will produce greater benefits to consumers over the long run.

In conclusion, I ask that the members of this Committee pause to give this bill, and its implications for customers, careful consideration. And, then I encourage the Committee to give this bill a "do not pass" recommendation. Thank you.

David Hoffman
PPL Montana
431-6783c
3/30/07

NorthWestern Energy

NorthWestern Energy/PPL Montana:
2007-2014 Power Supply Agreement

FACT SHEET:
July 2006

NorthWestern Energy is the Default Supplier for its electricity customers in Montana who do not purchase their own source of supply. This is a very important obligation and one that we take very seriously. The 2005 Electric Default Supply Resource Procurement Plan outlines the current and future procurement activities that we believe are necessary for providing this service. The role of the Default Supplier has changed considerably since it was first implemented almost 10 years ago. What was once envisioned as a short-term "provider of last resort" for an unknown number of customers is now known to be a long-term commitment to providing all of our customers with reliable and affordable electricity supply. We have made substantial progress in recent years to move to a long-term planning horizon. The most recent accomplishment is a new agreement with PPL Montana, which will take effect July 1, 2007 upon the expiration of the existing contracts.

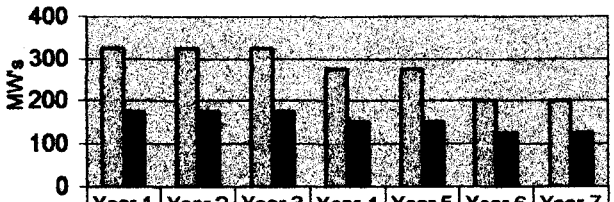
This Fact Sheet provides on overview of NorthWestern Energy's Power Purchase Agreement (Agreement) with PPL Montana, including key provisions, benefits, cost and rate/billing impacts, and a brief description of our future electricity procurement plans. In the event of any inconsistency between what is provided in this Fact Sheet and the confirmation and standard form agreement, the confirmation and standard form agreement apply.

PPL Montana - Power Supply Agreement

Term: July 1, 2007 through June 30, 2014

Quantity: Firm blocks of declining on-peak/off-peak power over the seven-year term of the Agreement, as illustrated in the following chart. Total contract volume is 13.7 million megawatt hours (MWh).

Quantities



	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
On Peak	325	325	325	275	275	200	200
Off Peak	175	175	175	150	150	125	125

Prices: The price for each product is fixed on a quarterly basis. The price will increase, on average, 2.3 percent per year over the life of the contract. The following table shows the prices starting July 1 of each year under the Agreement:

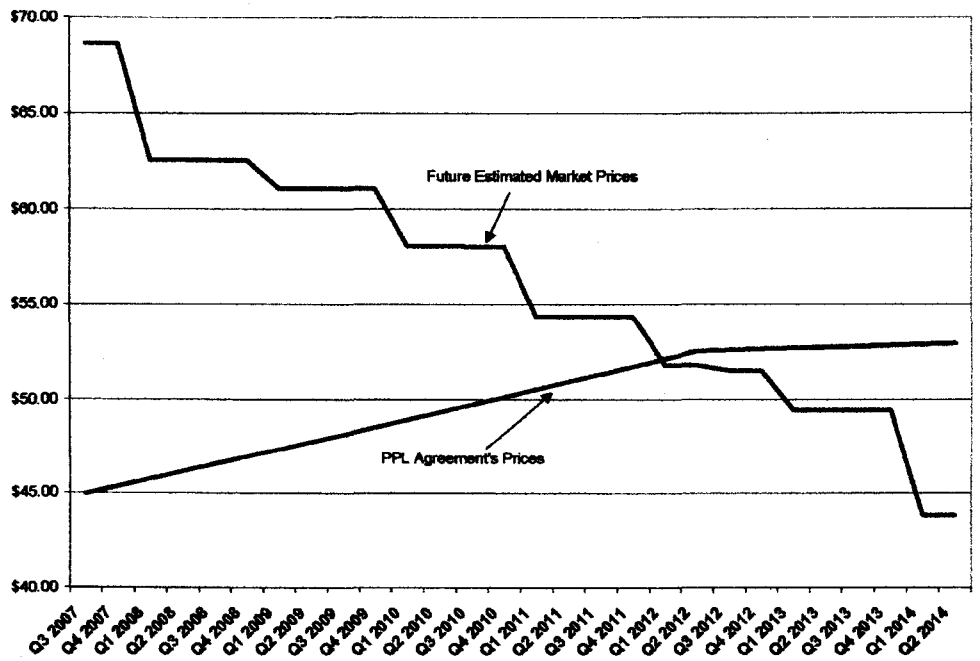
Date	Price/mWh
July 1, 2007	$44.95
July 1, 2008	$46.55
July 1, 2009	$48.15
July 1, 2010	$49.75
July 1, 2011	$51.35
July 1, 2012	$52.60
July 1, 2013*	$52.80

**Ending contract price in 2014 is $52.95*

Benefits: This seven-year Agreement includes a number of benefits. They are:

- Helps provide customer **rate certainty** and rate stability over the next several years.
- The Agreement is priced substantially below current electric market levels. It represents a **significant discount** to forward market prices.

Price per MWh



This graph compares the Agreement to today's estimated forward market prices on a $/MWh basis.

- Provides a **significant portion** of the near and mid-term Default Supply energy needs.
- This Agreement acts as a "bridge", allowing NorthWestern Energy the **flexibility to diversify** its resource mix and reduce its reliance on any one provider. For example, PPL Montana currently

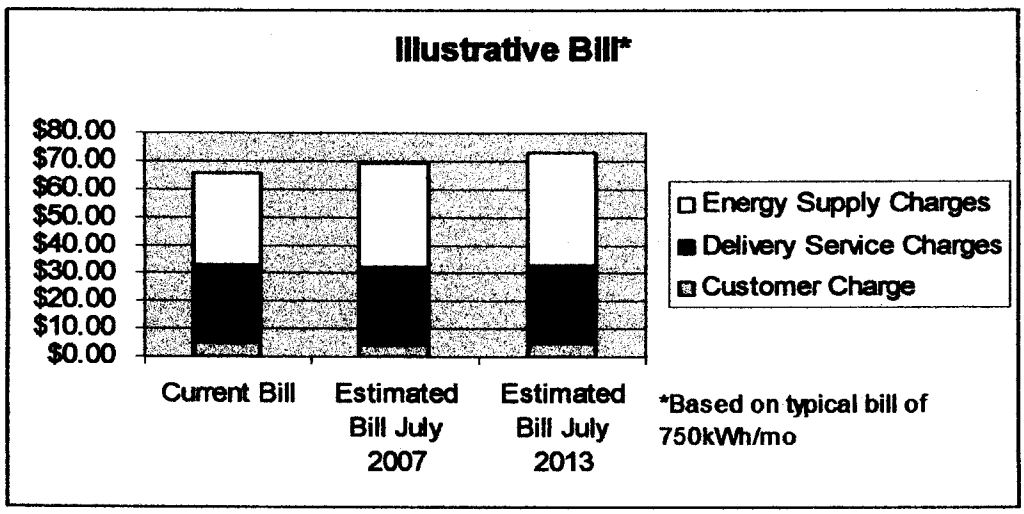
provides approximately 55-percent of the Default Supply energy needs. In 2007, the number will be 37-percent and is expected to be roughly 23-percent by 2014.

- The Agreement is **consistent** with NorthWestern Energy's 2005 Electric Default Supply Resource Procurement Plan filed with the Montana Public Service Commission (MPSC) in December.
- The pricing structure offers **specific advantages** to NorthWestern Energy's customers:
  - The steep discount to current market early in the Agreement helps mitigate customer "rate shock". The initial discount is over $23/MWh compared to the Mid-Columbia 2007 trading market.
  - While the affect of this new agreement for typical residential electric customers is expected to result in an increase of approximately 7-percent in their total bill, without this stepped-pricing structure, the impact would've been much greater. The estimated increase is based on a proposed rate mitigation plan that NorthWestern proposed in its recent annual Electric Default Supply tracker filing and estimated market conditions in 2007-2008.
  - The approximate amount of the overall discount over the life of the agreement is $100 – 125 million based on current market prices.
  - Out-year pricing is approximate to the current estimated cost to build new generation.
- Reliability is **assured** – we are purchasing "firm" power.
- Underlying price risks related to environmental issues, property taxes and so on are **retained** by PPL Montana.
- **Mitigates** market price volatility.

NorthWestern Energy has executed the Agreement, which will be evaluated by the Montana Public Service Commission (MPSC) at some point in the future.

The Relation of Default Supply Costs to Customer Bills

The following table illustrates the estimated impact of this Agreement on a typical residential customers' bill beginning July 1, 2007 and on July 1, 2013, compared to today's bills:



**Note: Future customer rate estimates are based on information available today and are meant to be illustrative only. Future rates will depend on the actual energy costs in place at the time. NorthWestern Energy does not earn a profit on the Energy Supply Charges component of the bill.*

Next Steps

The addition of the new PPL Montana Agreement, along with the other contracts assumed to be in the portfolio, will provide about 70 percent of the necessary electricity to meet customers' needs in 2007/2008. To further augment the electricity portfolio, NorthWestern Energy plans to conduct the previously announced electricity auctions and explore additional bi-lateral negotiations for supply needs with terms of up to 5-years. NorthWestern anticipates that the first auction will be held this fall, followed by a second auction, if necessary, in the spring of 2007.

NorthWestern will also begin to consider the acquisition of long-term, rate-based generation resources in the spring of 2007, once the results of the auctions are fully implemented into the portfolio and any legislative changes are known. In addition, NorthWestern will continue to actively exploring market opportunities with other energy developers, financial institutions, utilities, and other power marketers for resources.

For additional information about NorthWestern Energy or our Default Supply Electricity Procurement Plan:

www.montanaenergyforum.com
www.northwesternenergy.com

NWE responds to editorial on proposed sale to BBI

By MIKE HANSON
NorthWestern Energy

After reading the Billings Gazette's recent opinion (Feb. 8) regarding the sale of NorthWestern to Babcock and Brown Infrastructure, we're not only disappointed — we're dismayed. Why? Despite two visits to the editorial board, the board has announced a fundamental policy position — not shared by anyone else involved in the proceedings — that is premised on factual errors and misleading statements. Again, here are the facts:

If the Montana Public Service Commission should "just say no" to the sale, how are Montana consumers better served by the alternative? [redacted] BBI has clearly stated it is a long-term investor that wants to invest in Montana's growth and economic development.

The Gazette falsely asserts that NorthWestern would not be subject to all of the same U.S. SEC reporting requirements if it were purchased by BBI. This is simply not true. NorthWestern will continue to have publicly traded debt in the U.S. and, therefore, we're subject to the same filing requirements that we make today with the exception of shareholder solicitations (proxy statements). In addition, all of this same financial information is filed annually with federal and state regulators.

The Gazette mocks BBI's track record as a long-term investor. While it's true that BBI was formed in 2002, the company was created by Babcock and Brown, which was formed more than 30 years ago in the U.S. BBI based its decision to purchase NorthWestern on a 40-year planning horizon, which should reassure our customers — a horizon our current shareholders certainly do not have.

The Gazette attempts to draw parallels between this acquisition and NorthWestern's purchase of Montana Power in 2002 as a way of leading readers to believe that BBI is somehow destined to follow the same path. Most of BBI's other businesses have been in existence well over 50 years, and they are all financially healthy and growing. More importantly, NorthWestern is entirely protected from the activities of BBI's other businesses and, in fact, BBI itself. We call this "ring fencing." There is simply no way for history to repeat itself in this manner. This is another fact that has been shared repeatedly.

The Gazette states that the testimony of the Montana Consumer Counsel's witness was blacked out "in an ill-advised attempt to protect BBI" and implies that BBI blacked out the witness' testimony. In fact, the witness' testimony was blacked out by the MCC based on its understanding of the PSC's protective order. BBI and NorthWestern do not have the right to black out testimony of other intervenors, nor do the intervenors black out testimony provided by BBI and NorthWestern. The appeal filed by the Associated Press and the Gazette's State Bureau recognizes the fact that the testimony filed by BBI was "substantially less redacted (blacked out)" than the MCC testimony.

Interestingly, the Gazette praises itself for its role in making public previously blacked-out information submitted by BBI — and then apparently failed to read it. Had it done so, the paper would have understood that BBI and NorthWestern disagree with much of the analysis submitted by the MCC — a significant omission of fact from its editorial. We invite you to read the BBI testimony filed by Jonathon Sellar where these disagreements are discussed at length. However, we can assure our customers that the sensational assertions are simply not true.

The Gazette states in its opinion "that in a recent guest opinion by BBI, CEO Steve Boulton said that NorthWestern will need higher rates from Montana customers." The Gazette missed the point of what Boulton wrote, and the statement is incorrect and out of context. Again, we invite people to read the guest opinion for themselves, but he was referring to the well-known fact that Montana's utility is not earning its authorized rate of return. The actual sentence reads: "If the PSC agrees that a rate adjustment is necessary, it will only allow NorthWestern to adjust for known and measurable changes in the cost of doing business — regardless of who owns the company."

We agree with The Gazette on one point: This is a question of trust. The Gazette ignored the facts we provided and chose to base its opinion on errors and omissions. We doubt that the decision was reached after a careful examination of all facts. Had it done so, we believe the board would have come to the same conclusion every other intervenor (those who have been examining all the facts) reached: The sale could and/or should be approved with certain conditions.

In fact, the MCC's expert witness — who was quoted in The Gazette opinion — has outlined seven conditions for approval of which NorthWestern and BBI agree with most. We hope to work through our differences with the recommendations and reach an amicable agreement we can all live with.

So, in light of the facts, how is The Gazette's opinion in the best interests of our customers and Montana? We invite you to understand the facts for yourself and form your own opinion.

Mike Hanson is chief executive officer for NorthWestern Energy.

To learn more

Public hearings on the proposed $2.2 billion sale of NorthWestern Energy, the largest electricity and gas distribution utility in Montana, to Babcock & Brown Infrastructure of Sydney, Australia, are scheduled for these cities in central and Eastern Montana:

- Billings, 6:30 p.m., Feb. 24, Montana State University-Billings, Lewis and Clark Room in the Student Union Building.
- Glasgow, 1 p.m., March 1, in the Elks Club.
- Havre, 7 p.m. March 8, Hill County Electric Co-op office.
- Lewistown, 2 p.m. March 5, Community Center.
- Great Falls, 7 p.m., March 5, MSU-College of Technology, Heritage Hall.

The Montana Public Service Commission is scheduled to begin formal hearings on the buyout proposal March 14 in Helena.

David Hoffman
PPL Montana
431-6783
3/30/07

Community Choice A

ENVIRONMENTAL RESOURCES
EXHIBIT NO. 17
DATE 3-30-07
SUBJ. NO. HB 25

492 E

When California deregulated elect
switched to buy "green" energy. Af
consumer choice of electricity providers was suspended. Most Californians now get their electricity from the same utilities that provided it before deregulation. Community Choice Aggregation offers an opportunity for Californians to once again choose their electric provider and the source of their electricity.

-1 Lee Warren MLCT 3-30-07

What is Community Choice Aggregation?

Community Choice Aggregation (CCA) enables California cities and counties – or groups of cities and counties – to supply electricity to the customers within their borders.

Unlike a municipal utility, such as the Los Angeles Department of Water and Power or the Sacramento Municipal Utility District, a CCA does not own the transmission and delivery systems (i.e., the poles and wires).

Instead, a CCA is responsible for providing the energy commodity (i.e., the electrons themselves) to its constituents – which may or may not entail ownership of electric-generating resources.

The value of forming a CCA

Many communities want to increase the amount of non-polluting, renewable energy they use, and are looking at Community Choice Aggregation as a mechanism for doing so.

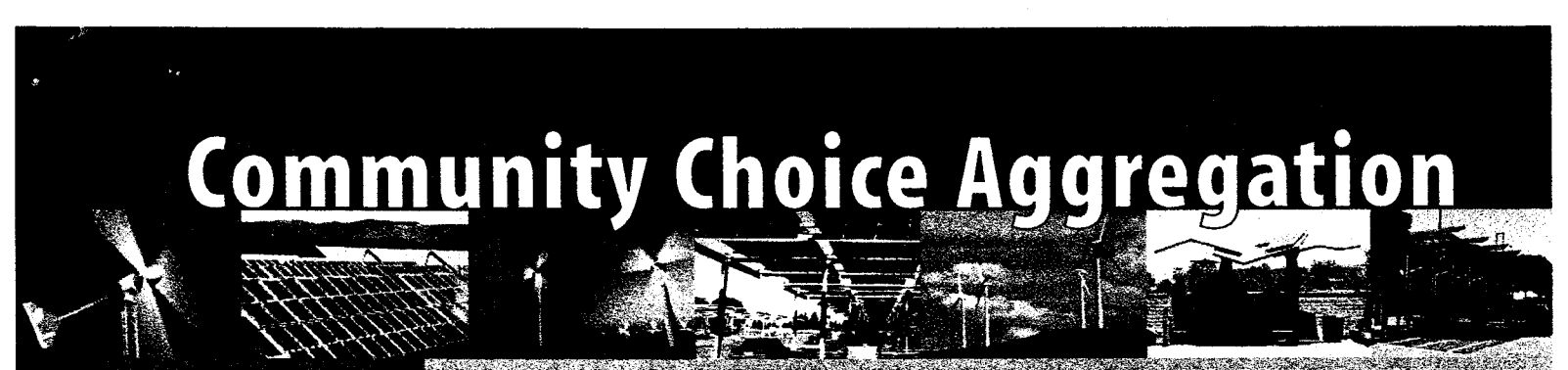
Local control over retail electric rates is another important motivation for initiating CCA. Investor-owned utilities currently propose service rates for electric generation, transmission and distribution, and the California Public Utilities Commission either approves or rejects these proposals.

Because decisions are for classes of customers across the utility's territory, customers in Arcata, for example, pay the same rates as those in Fresno.

Historically, public utilities across the nation have been able to offer rates that are 15-20% lower than investor-owned utilities. And as an example of dependability, Roseville Electric has been selected as the nation's most reliable utility serving less than 100,000 customers for five years in a row.

Under CCA, decisions about rates, generating resources and public benefit programs will be made locally and be accountable to local customers.

Community Choice Aggregation



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-1 Lee Vinnan WLCT 3-30-07

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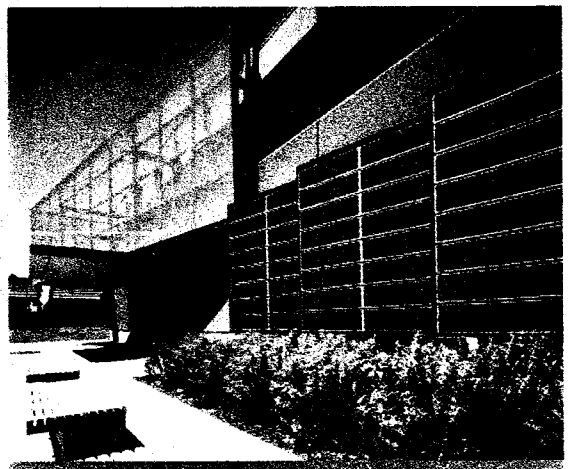
Community choice in California

Assembly Bill 117 removed a significant organizational hurdle for local governments interested in providing electricity to their communities.



After deregulation of California's electricity markets in 1997 (through AB 1890), many new power suppliers entered the state. For the most part, these suppliers marketed to high-volume electricity users to achieve higher returns on their marketing investments.

However, some offered consumers the option of clean, renewable energy. In every case, the choice to switch from investor-owned utility (IOU) service was made by individual consumers or businesses.

With the electricity crisis in 2000-01, the law was changed and the ability of consumers to enter into electric service contracts directly with suppliers was suspended.

In 2002, Community Choice Aggregation (AB 117) was signed into law. This legislation removed a significant organizational hurdle for local governments interested in providing electricity to their communities.

Unlike AB 1890, which required each customer to specifically choose non-IOU service ("opt-in" to the new service), formation of a CCA assumes that all utility customers within the CCA's boundaries will become CCA customers. However, customers within the CCA's boundaries may choose to continue their utility service, to "opt-out" of the CCA program.

Implementation rules

The California Public Utilities Commission (CPUC) is in charge of creating guidelines for a CCA program. It is now preparing materials to help assist potential CCAs develop implementation plans and complete the registration process.

The CPUC also sets the Cost Responsibility Surcharge for customers who leave IOU service. This surcharge ensures that all remaining IOU customers will not pay higher rates when customers leave IOU service. It includes paying back the costs of expensive, long-term power contracts entered into during the 2000-01 energy crisis, and other uneconomic IOU costs.

The Cost Responsibility Surcharge is determined by comparing these uneconomic costs to the current market rates for electricity. As market rates increase, the surcharge will decrease. Most of the contracts entered into during the crisis expire by 2012.

Is CCA feasible for your community?

Historically, public utilities across the nation have been able to offer rates that are 15-20% lower than investor-owned utilities.

CCA is a substantial undertaking for any community, but the rewards may be worth the effort and risk.

One of the first things to consider is whether there is the political commitment to form and, ultimately, implement a CCA. Local elected officials will make the decision about establishing a CCA and are accountable for its successes or shortcomings. Many officials may not be willing to accept this political risk.

Implementing a CCA program will take several years. As a result, the elected officials who initiate the process of forming a CCA may not be the ones who vote to establish it, or make resource selection and rate-setting decisions. And there will likely be opposition to CCA formation within the community.

■ The benefits of CCA

The most common reasons for forming a CCA include:

- → Increased use of renewable generation.
- → Local control of rate setting.
- → Economic growth.
- → Lower rates.

A community will need to present strong incentives for choosing CCA to its potential customers. Many California cities and counties have agreed to reduce greenhouse gas emissions or have other, similar environmental goals. CCAs can help by increasing local consumption of renewable energy.

Local control of electric rates can also allow a community to attract new businesses and retain existing ones by offering targeted incentives to these customers.

Other communities may want to develop generation projects that increase local employment. Some may focus on creating income to offset municipal expenditures.

And perhaps most importantly, preliminary feasibility studies indicate that CCAs, through the use of local government financing, should be able to reduce electric rates compared with IOUs.

This reduction is because private financing costs are more than twice those of a CCA. Based on a pilot project funded by the California Energy Commission, CCA capital costs were about 5.5%, compared to 12.9% for IOUs.

This capital financing advantage is especially important for high-capital, low-operating-cost facilities like renewable energy generation.

■ The risks of CCA

The biggest risk is that CCA rates may be higher than utility rates. Well-managed power purchasing and development should mitigate this risk. A well-balanced portfolio of resources that includes short- and long-term contracts and CCA-financed new generation projects should result in competitive rates.

One way to hedge against volatile energy prices is to create a rate stabilization fund, which many municipal utilities do. This will allow a CCA to hold prices steady, even when fuel prices rise. And there is no fuel cost to generate electricity from wind and solar sources.

Future regulatory decisions could result in cost increases for CCA programs. Most of the decisions about CCA programs have already been made by the CPUC, however. Local governments participated in that process, and their concerns were favorably reflected in those decisions. Continued participation in CPUC proceedings will be necessary to protect CCA interests.

Steps you'll need to take

Communities considering CCA formation should analyze:

- → Forecasted IOU rates.
- → The Cost Responsibility Surcharge.
- → CCA commodity costs (including generation ownership, power purchase contracts, renewable energy contracts and spot-market purchases).
- → Community energy use profiles (daily and seasonal) throughout the year.
- → California Independent System Operator charges.
- → Operations and scheduling costs.
- → Financing costs.
- → Revenue offsets and available financial incentives.

Communities will also need to communicate with constituents throughout this process. Some communities have already established stakeholder groups to contribute to the planning process. Others have scheduled public meetings to keep their residents and businesses informed.

Should you find CCA partners?

Another big question for communities considering CCA is whether or not to partner with other like-minded communities. AB 117 allows groups of cities and counties to join together to establish a CCA program. This provides economies of scale for energy contracts, administration costs and when interfacing with investor-owned utilities.

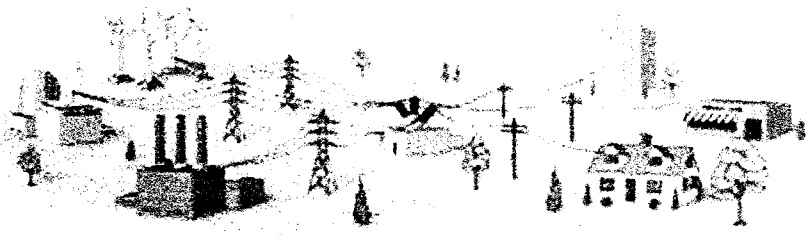
A study of seven Bay Area communities investigating CCA found that if they formed one joint CCA program instead of seven individual ones, they could save an additional 34%. A joint CCA may also reduce variability in electric loads (fewer usage peaks and valleys), allowing for larger baseload contracts (with generally lower prices than peaking or spot-market contracts).

Joint CCA programs will likely require a joint powers agreement. That pact could result in the creation of a single governing body making decisions (about supply and rates) on behalf of all CCA customers, or it could be more limited, where cities or counties act together on some issues and independently on others (for example, group power purchases and/or resource investments, but setting rates separately).

An individual CCA could also act with another CCA to provide some services, such as project financing, billing and regulatory review. Getting good legal advice from your city or county attorney is essential.

Initially, most CCAs will likely contract for administrative operations, which can be accomplished by using a single energy service provider or multiple contractors (for example, one for scheduling power deliveries, another for customer service, and a third for legal or regulatory services). Eventually, the CCA may hire its own staff to perform some or all of these functions. The CCA should make these decisions to ensure the program's success and should be based on community preferences.

The infrastructure of buying electricity from a CCA



GENERATION
- → provided by CCA or investor-owned utility

TRANSMISSION
- → remains utility only
- → lines open to all suppliers

DISTRIBUTION
- → remains utility's responsibility
- → service remains the same
- → rates remain regulated

CUSTOMERS
- → choose generation suppliers

This fact sheet was made possible with funding from the U.S. Department of Energy and the California Energy Commission.

California cities and counties that are exploring formation of a CCA:

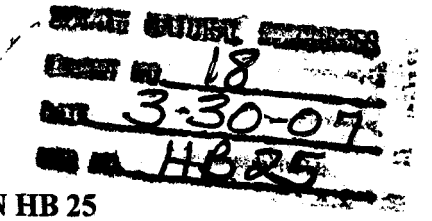
- → Berkeley
- → Beverly Hills
- → Chula Vista
- → Emeryville
- → Kings River Conservation District (12 cities in the Fresno area and Kings County)
- → Los Angeles County
- → Marin County
- → Oakland
- → Pleasanton
- → Richmond
- → San Diego County
- → San Francisco
- → San Marcos
- → Vallejo
- → West Hollywood

For more information

Local Government Commission
1414 K St., Suite 600
Sacramento, CA 95814-3966
(916) 448-1198
www.lgc.org/cca

editing+design: dave davis

Brad Molnar
3-30-07



BRAD MOLNAR'S TESTIMONY ON HB 25

I have always stood as a supporter HB 25. I have even championed HB 25 over competing legislation. However my support has always been provisional and my concerns have never been addressed so I now rise to offer my insights and ask that you give them consideration HB 25 goes through the system.

I believe that my concerns are acknowledged and it is simply hoped that they are not adopted so that business as usual can be accomplished while putting new tires on a collapsed chassis.

Those of you that have been around for a while may remember that a well intentioned Senator in 1997 pushed a good sounding deal. Very few understood it yet followed on faith and strength of argument. The concept became internalized by the Senator, focus got lost, and the rest is history. This is our chance to learn from history. Hopefully, if HB 25 becomes law it will be thought out well enough that we will not need to have major rewrites the same as we have had every session since 2001. Hopefully the voice of the utility will not, once again, be the only voice heard. To that end I offer the following:

SUPPLY PROCUREMENT

Re-regulated or not, we shall be "in the market" in a very big way for many years to come. The problem is that if NWE is a bidder into the supply, therefore also a competitor to the other bidders, then the other bidders will not give the required proprietary information to NWE. They won't do it for energy supplies and they won't do it for generation construction. This lack of competition will certainly drive up prices. There needs to be third party oversight established. It can't wait till we have RFPs with no respondents. (Latest auction)

I have raised this issue with Rep. Olson since the first hearing. As a matter of fact I raised it last session on Rep. Olson's then re-reg. bill. There can only be one reason to continue to ignore the obvious. If third party oversight can not be accomplished then HB 25 should not go forward.

UPON PASSAGE

Upon passage I can generate more electricity by shuffling across the floor in wool socks than NWE can generate in a year. They will have nothing to generate with for a long time. And, by statute, they will have no obligation to acquire generation. It's all voluntary. NWE can continue in our current happenstance. Supposedly the reason for HB 25 is to institute a vertically integrated utility. But how can you have a vertically integrated utility without generation capacity? Throughout the BBI/NWE hearings no one said that there was any intention to build generation. Only two transmission projects were mentioned. The written testimony acknowledged the need to serve the default supply but doing so through the acquisition of generation assets was not mentioned other than as possible legislation. When specifically asked about procuring a regulating capacity Steve

Bolton CEO of BBI had no idea what it was. Certainly they had never discussed generation. At my Billings meeting I asked Mr. Jaarsveldt, BBI's general manager of regulation, and David Gates, NWE vice president of wholesale operations, "We need base load, sculpted load and peak load capacity. If HB 25 passes what will be your first two construction projects?" The answers were, "Don't know" and "Haven't thought about it." If all the PSC can do is comment of procurement plans (Current practice and re-stated in HB25) then how have we taken control of our destiny? We really need the legislative authority to order that certain procurement happen; be it long term contracts and/or generation capability. To do otherwise is to wait and see what suits NWE shareholders rather than NWE ratepayers which is our status quo. To do otherwise is to render this bill meaningless for currently NWE can build generation and put it into the supply portfolio. The same as they tried with First Montana Megawatts. To do otherwise is to grant capacity to NWE without obligation. Perhaps generating enough theoretical earning capacity to raise appraisal values to $37 per share is the underlying intent

THE MORNING AFTER/THAT DANG REALITY

Let's assume that HB 25 passed in its current form. How much generation can we expect? Using the most recent numbers from the SME project near Great Falls the cost of four 250 megawatt plants would be $3B. That would totally idle Colstrip 1-3 and export the hydro resources out of state. But PPL would still control transmission rights and the Q for new energy supplies on our existing lines is about 20 years so we would need to build new transmission line (NWE would like that but rate payers would not). This could easily be another several billion dollars and both would take decades.

Let's assume HB 25 in its present form passes and NWE opted to build a regulation generator. (Because of regional wind development and specifically Judith Gap this would be a matter of self defense.) It would probably be a gas generator. The largest cost would be the natural gas. Natural gas is federally deregulated. So what would the PSC regulate? The procurement contract. This would be simple because no one would hand their bid over to their competitor in the bidding process. And, as is currently the case with the Basin Creek facility, we would only regulate the maintenance contract. Is this what you had in mind for a re-regulated system? Would we even want a rate based gas plant on the backs of the ratepayers when certainly the technology for such plants would certainly make any plants built today obsolete in twenty years? Perhaps, just perhaps, the best avenue for this particular development is long term lease. Perhaps it should not even be a part of this debate.

ALL ON THE TABLE/YOU OWE IT

The stated reason HB 25 was brought forward is that NWE wants the ability to acquire rate based generation. However, they do not want their generation to be rate based. (?) That is odd. NWE controls 222 MW of thermal generation in Colstrip 4. Short term 90 MW are pledged to the Default supply. The balance is leased out. Through out their

written testimony NWE talked of buying out the contracts. Now is a good time. The contracts should be supplied to the people of Montana at just and reasonable rates. This is very much against my docile nature so let me explain why I take this stand. (Hand out)

The reason NWE appeared large enough to buy Montana Powers transmission assets is that, apparently, they were willing to commit fraud and continue the fraud until the house of cards came down. Because of a poor credit rating NWE never had a capacity to procure electricity in long enough contracts, or natural gas with favorable enough terms, to assure their customers the lowest long term costs as provided by law. Nor were they capable of acquiring short, medium, and long term electricity contracts (as required by PSC rule) so we have always been in the market as panicked buyers. Our families and employers have suffered. If the worst that happens to NWE, and their share holders, is that they are punished by receiving "just and reasonable rates" they should change their name to "The Smiley Electricity Company."

PREAPPROVAL/A NECESSARY EVIL

I stand in favor to the portion of the bill that maintains pre-approval as a methodology to promote development. I do this despite the unqualified failure of the three most recent pre-approvals. Docket D99.4.82 deregulated Montana Power and PPL despite prohibitions of same. Docket D2001.1.5 The sale of Montana Power Co. transmission assets to NowthWestern Corp. based on a transition plan that was never accepted and fraudulent financial information given. And Docket D2005.2.14 which allowed Judith Gap wind farm into the default supply despite the fact that ancillary supplies were known to be in short supply and cost warnings from the Montana Consumer Council. As you know we face imminent consequences because of this shortsightedness.

The problem is systemic and needs to be addressed but there is no workable substitute under today's financial realities.

CONCLUSION

There is no rush. We have seven year's worth of electricity contracts and NWE is now financially capable of getting longer term contracts. Just like co-ops. The original "De reg" bill SB 390, actually handled two major problems and established a five year study on the desirability of deregulation. The study was cut to two years and deregulation (EWG status) happened on May 25, 1999. Had the PSC waited just six months more the California melt down would have started and shown the downside of two much market exposure. In contrast HB 25 is the product of several meetings of the FRET interim committee and massive amounts of amendments. Do you really trust six people on a Freestanding Conference Committee to make the final determination for our energy future? The best course of action is to find out who will own NWE and how solid they turn out to be. And to study not what words will be used to create another vertically integrated utility but rather to consider what happens after the bill is signed and the cameras go away. A good start would be to subsume into HB 25 the study bill HB 626. The intent of HB 626 is to make our system as functional for the people of Montana as

possible regardless of structure label. If you do include it be sure to keep application away from the FRET sub committee. Partisan solutions and utility controlled legislators have proven to not be the answer.

If this is going into a sub committee I will gladly work with them and, should you so ask, will work on the necessary amendments for my recommendations.

POLITICAL POTPOURRI IV

Questions? Concerns? Comments about Gov't or energy policies?
Address them to bmolnar@mt.gov

BANKRUPTCY MEANS NEVER HAVING TO SAY YOU'RE SORRY

Ask any person why NorthWestern Energy (NWE) went bankrupt and they will recite, "Bad outside investments." Yeah right. How about fraud?

After months of sworn testimony, in Feb. of 2002, NWE acquired the transmission assets of the old Montana Power Company. They swore they were worth billions of dollars and obtaining the transmission assets would only bring stability and great service to the people of Montana. September 2003 NWE declared bankruptcy; but not because several acquisitions suddenly went bad.

According to a Securities and Exchange Commission (SEC) report issued March 7, 2007 NWE, mainly concerning two subsidiaries, Blue Dot and Expanets, materially misrepresented their financial position for the first three quarters of 2002 by 176%, 618%, and 109% respectively. When these two companies were written off they were written off as a $900M loss. During the acquisition process they were shown as substantially adding to NWE's financial strength.

False strength was shown by not publicly recognizing a mounting accounts receivable problem with the subsidiaries. Cash reserves set aside to handle the accounts receivable shortage reappeared as fresh earnings. The net result was NWE overstated its income for the first three quarters of 2002 by 16%, 19%, and 39% respectively via understating Expanets operating loss for the first quarter of 2002 by 66% and overstating its operating income by approximately 86% and 270% for the second and third quarters of 2002.

Employing "improper accounting for billing adjustments" NorthWestern overstated its income by 98%, 46%, and 31% respectively for the first three quarters of 2002. And NWE understated Expanets operating loss by approximately 87% for the first quarter of 2002 and overstated Expanets operating income by approximately 1094% (Not a typo. It really is 1094%) and 164% respectively for the second and third quarters of 2002.

In the first quarter of 2002, $2.6M of Expanets income was derived by transferring funds dedicated to covering bad debt to the profit side of the ledger. Second quarter of 2002 $8.8M of Expanets income was derived from "reserve reductions". Third quarter of 2002 $27M of Expanets income was derived from "reserve reductions". For the third quarter alone this allowed NWE to be able to post a $14.6 million dollar profit for continuing operations rather than a significant loss.

Expanets bought out a competitor and the competitor agreed to make payments so as to not have Expanets compete in certain markets. These "non-compete" payments were never reported as "unusual transactions". Rather, they showed up as normal income from continuing operations. In first three quarters of 2002 these undisclosed non-compete

payments boosted NWE's shown income from continuing operations by 25%, 31%, and 68% respectively.

At the same time these subsidiaries were showing healthy profits NWE was providing intercompany advances. First quarter of 2002 advances totaled $63.3M. By the end of the third quarter of 2002 the intercompany advances totaled $113.4M. These advances could no longer be hidden so were reported in September of 2002.

When the acquired subsidiary, Blue Dot, acquired other companies it often tendered its own stock as partial payment. A third party appraiser in 2nd quarter of 2002 appraised Blue Dot common stock as "worthless". NorthWestern did not immediately disclose this loss of value but rather charged off the losses to minority interests (those acquisitions that had taken the now worthless stock). This allowed NWE to overstate its income from continuing operations by 63%.

These are the findings of the Securities and Exchange Commission which basically has told NWE to please stop being so darn fraudulent. Without admitting or denying the findings Northwestern Corporation has said "OK." I don't think it is "OK."

Not only were many people's lives, business, and retirements ruined but NWE was never in a financial position to be the default supplier capable of providing electricity at "just and reasonable rates" for Montanan's as required by law. Because of their precarious financial position they had to pay higher amounts (just like anybody with poor credit) and pass the higher costs on to you.

Under current interpretation of Montana law, if a utility via the Montana Public Service Commission, engages in fraudulent activities and no one discovers the fraud within thirty days the fraud is irreversible by the courts. Conversely, you can take action up to two years after the discovery of the fraud (IE. You purchase a home but when you go to sell it you discover that the seller did not disclose it was built on a toxic waste dump). I and Rep. George Everett (R) Kalispell tried to change the law (HB 659) to hold utilities and the PSC to the same standard as you are; two years after discovery. Though originally aimed at the fraud and collusion I accuse the PSC and PPL of in the deregulation of Montana Powers generating facilities it certainly would have applied to this issue or to any potentially dastardly deeds in the BBI/NWE question. The bill had only two opponents; NorthWestern Energy and (after a 3-1-1 vote to oppose the anti-fraud bill) Greg Jergenson, Chairman of the Montana Public Service Commission. The only legislative committee member to speak against HB 659 was Rep. Alan Olson (R) Roundup who offered that HB 659 was "a solution looking for a problem that might cause problems in the future." The anti fraud bill AKA HB 659 died in committee.

Brad Molnar
Montana Public Service Commissioner

Brad Mackey
444-6167
3-30-07

UNITED STATES OF AMERICA
Before the
SECURITIES AND EXCHANGE COMMISSION

SECURITIES EXCHANGE ACT OF 1934
Release No. 55416 / March 7, 2007

ACCOUNTING AND AUDITING ENFORCEMENT
Release No. 2573 / March 7, 2007

ADMINISTRATIVE PROCEEDING
File No. 3-12585

In the Matter of **NORTHWESTERN CORPORATION,** **Respondent.**	**ORDER INSTITUTING CEASE-AND-DESIST PROCEEDINGS, MAKING FINDINGS AND IMPOSING A CEASE-AND-DESIST ORDER PURSUANT TO SECTION 21C OF THE SECURITIES EXCHANGE ACT OF 1934**

I.

The Securities and Exchange Commission ("Commission") deems it appropriate that public cease-and-desist proceedings be, and hereby are, instituted pursuant to Section 21C of the Securities Exchange Act of 1934 ("Exchange Act") against NorthWestern Corporation ("NorthWestern" or "Respondent").

II.

In anticipation of the institution of these proceedings, Respondent has submitted an Offer of Settlement (the "Offer") which the Commission has determined to accept. Solely for the purpose of these proceedings and any other proceedings brought by or on behalf of the Commission, or to which the Commission is a party, and without admitting or denying the findings herein, except as to the Commission's jurisdiction over it and the subject matter of these proceedings, which are admitted, Respondent consents to the entry of this Order Instituting Cease-and-Desist Proceedings, Making Findings and Imposing a Cease-and-Desist Order Pursuant to Section 21C of the Securities Exchange Act of 1934 ("Order"), as set forth below.

III.

On the basis of this Order and Respondent's Offer, the Commission finds[1] that:

Summary

During the first three quarters of 2002, NorthWestern filed quarterly and current reports with the Commission that materially misstated NorthWestern's financial position and misrepresented or did not disclose required information about its non-utility businesses, Expanets, Inc. ("Expanets") and Blue Dot Services, Inc. ("Blue Dot"). In its filings, after the effect of taxes, NorthWestern overstated its income from continuing operations for the first three quarters of 2002 by approximately 176%, 618%, and 109%, respectively, due to the company's improper accounting for accounts receivable, adjustments to customers' bills, and allocation of losses to minority interests. NorthWestern also misrepresented or did not disclose, among other things, the effects of significant problems with Expanets' new information technology system, the material impact of Expanets' reserve reductions and its receipt of non-compete payments on Expanets' income, large intercompany advances NorthWestern made to support Expanets and Blue Dot, and the timing of anticipated payments from the sale of certain utility assets. Through its financial misstatements, misrepresentations, and omissions, NorthWestern obscured the continuing poor performance of its subsidiaries at a time when it was publicly relying on these subsidiaries' operations to strengthen its financial condition.

Respondent

1. NorthWestern, a Delaware corporation with its principal executive offices in Sioux Falls, South Dakota, operates a regulated utility business in South Dakota, Nebraska, and Montana. During the period of conduct discussed herein, NorthWestern consolidated the financial results of two non-utility entities, Expanets and Blue Dot. NorthWestern's common stock was registered with the Commission under Section 12(b) of the Exchange Act and traded on the New York Stock Exchange until it was delisted shortly before NorthWestern declared bankruptcy in September 2003. In November 2004, NorthWestern emerged from bankruptcy. Its common stock is now registered with the Commission pursuant to Section 12(b) of the Exchange Act and trades on the NASDAQ Global Select Market.

Other Relevant Entities

2. Expanets, formerly headquartered in Englewood, Colorado, was formed by NorthWestern in 1997 and provided networked telecommunications equipment and services to medium-sized businesses nationwide. NorthWestern wrote off substantially all of its investment in Expanets during the fourth quarter of 2002 as disclosed in the company's 2002 Form 10-K and announced its intention to sell Expanets in April 2003. In the second quarter of 2003, Expanets'

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[1] The findings herein are made pursuant to Respondent's Offer of Settlement and are not binding on any other person or entity in this or any other proceeding.

operations were discontinued, and in May 2004, Expanets (n/k/a Netexit) filed for Chapter 11 bankruptcy protection. Proceeds from the sale of Expanets' assets were distributed in bankruptcy.

3. Blue Dot, formerly headquartered in Sunrise, Florida, and Sioux Falls, South Dakota, was formed by NorthWestern in 1997 and provided heating, ventilation and air conditioning ("HVAC") services nationwide. NorthWestern wrote off substantially all of its investment in Blue Dot during the fourth quarter of 2002 as disclosed in the company's 2002 Form 10-K and announced its intention to sell Blue Dot in April 2003. In the second quarter of 2003, Blue Dot's operations were discontinued, and NorthWestern thereafter sold or closed each of Blue Dot's HVAC businesses.

Background

4. For more than seventy years, NorthWestern operated a public utility business, providing electricity and natural gas to customers in South Dakota and Nebraska. In the late 1990s, NorthWestern formed Expanets and Blue Dot (the "non-utility businesses") to diversify into the telecommunications and HVAC sectors. NorthWestern's business plan was to acquire small telecommunications and HVAC companies and make them more profitable through central management, national branding and other economies of scale.

5. From 1998 through the end of 2001, Expanets acquired twenty-six small telecommunications companies and a sales division of a large competitor. From 1997 through the end of 2001, Blue Dot acquired over ninety different HVAC and plumbing companies. By the end of 2001, NorthWestern had invested hundreds of millions of dollars in Expanets and Blue Dot to make these acquisitions and build those subsidiaries' central management. However, Expanets and Blue Dot incurred losses during most years and posted only small profits in other years. Because of their performance, Expanets and Blue Dot required investments of substantial amounts of cash by NorthWestern.

6. In February 2002, NorthWestern effectively quadrupled its utility customer base by acquiring Montana Power Company ("Montana Power") for approximately $1.1 billion. NorthWestern originally financed its acquisition of Montana Power by utilizing, among other things, a $720 million acquisition loan. In March 2002, as part of a debt offering to retire the acquisition loan, NorthWestern issued $720 million in the form of senior notes.

7. The magnitude of NorthWestern's increased debt as a result of the Montana Power acquisition threatened the company's credit ratings. As a result, NorthWestern announced its intention to conduct an equity offering during 2002 to raise approximately $200 million to pay down its debt and improve its debt/equity ratios.

8. NorthWestern recognized that improvement in the performance of both Expanets and Blue Dot was critical to its planned equity offering. NorthWestern made public statements that both Expanets and Blue Dot would achieve 2002 targeted earnings and begin providing cash to the NorthWestern consolidated entity in 2002.

9. NorthWestern conducted its equity offering during the third quarter of 2002, and raised approximately $87 million. Also during the third quarter of 2002, NorthWestern completed its registration and exchange of new notes for $720 million of debt it incurred to purchase Montana Power.

10. In December 2002, NorthWestern disclosed that significant operational problems at Expanets and Blue Dot would materially impact the company's consolidated year-end financial results. In April 2003, NorthWestern filed its 2002 Form 10-K and simultaneously restated each of its Forms 10-Q for the first three quarters of 2002. NorthWestern's restated Forms 10-Q corrected material misstatements of previously reported financial results relating to Expanets and Blue Dot, and disclosed various operational difficulties these subsidiaries experienced throughout 2002. NorthWestern's 2002 Form 10-K further disclosed that the company did not anticipate recovering its past investments of hundreds of millions of dollars in Expanets and Blue Dot, and that neither entity would generate cash flows in sufficient amounts to provide meaningful contributions to service NorthWestern's debt load. NorthWestern's liquidity situation continued to deteriorate until the company filed for bankruptcy in September 2003. NorthWestern stock, which had traded for more than $20 per share in early 2002, was trading for less than a dollar by the time NorthWestern filed bankruptcy.

Problems Relating to Expanets' Computer System

Functionality of the EXPERT System

11. During 2000 and 2001, Expanets developed an information technology system, called the "EXPERT" system, to serve as a platform for virtually all of its operations, including sales, inventory, project management, billing, collections and financial statement preparation. Because of its planned scope and impact across operations, the functionality of the EXPERT system was critical to Expanets.

12. However, following its implementation in November 2001, the EXPERT system was unable to perform many of the basic tasks for which it had been designed. For example, for approximately a month after it was implemented, EXPERT could not generate any customer bills. From January through May 2002, many customer bills EXPERT generated were incomplete and inaccurate. Until approximately September 2002, the EXPERT system also could not properly apply cash collected to customer accounts or track the aging of accounts receivable balances. These problems materially affected Expanets' results from operations throughout 2002.

13. NorthWestern's Forms 10-Q for the first and second quarters of 2002 and associated press releases attached to Forms 8-K mischaracterized EXPERT's billing activities as "fully operational" or "operational" and failed to adequately disclose the magnitude of the system's problems and the material impact of those problems on Expanets' operations. In its Form 10-Q for the third quarter of 2002, NorthWestern disclosed that EXPERT had encountered some problems, particularly as to billings and collections, but did not disclose the extent to which these system problems had impacted Expanets' operations. NorthWestern did not fully and adequately disclose the severity of the problems with the EXPERT system and the impact of those problems on

Expanets' operations until April 2003 when it filed its 2002 Form 10-K and restated its Forms 10-Q for the first three quarters of 2002.

Aged Accounts Receivable

14. In anticipation that some customer accounts might prove uncollectible, Expanets maintained a "bad debt" reserve, which had the effect of reducing Expanets' operating income. Prior to its implementation of EXPERT, Expanets calculated its bad debt reserve based on the age of uncollected receivables outstanding in a given period. However, during the first and second quarters of 2002, the EXPERT system could not properly apply cash collected from customers to their accounts or accurately track the aging of Expanets' accounts receivable. As a result, rather than considering the age of all of its receivables, Expanets estimated its bad debt reserve based on the percentage of revenue that had typically resulted in uncollectible accounts receivable.

15. Expanets' bad debt reserve in 2002 was inadequate. As an initial matter, Expanets did not make appropriate adjustments for known aged receivables that pre-dated implementation of the EXPERT system.

16. Expanets also failed to increase its bad debt reserve despite the markedly increased difficulties with collections that resulted from the EXPERT system's problems. For example, since EXPERT could not apply cash collected to the proper accounts, Expanets could not determine from which customers to seek payment, causing uncollected receivables to age further.

17. Beginning in the third quarter of 2002, for the first time, the EXPERT system was able to generate accurate accounts receivable aging reports. These reports demonstrated that Expanets' uncollectible accounts receivable exceeded its existing bad debt reserve by tens of millions of dollars. Despite such data, Expanets did not increase its bad debt reserve or directly write off uncollectible accounts receivable.

18. In its first and second quarter Forms 10-Q, NorthWestern did not disclose information indicating that a loss as a result of its uncollectible accounts receivable was probable or reasonably possible. In its third quarter Form 10-Q, NorthWestern disclosed that the EXPERT system's problems might lead to an increase in Expanets' bad debt reserve. However, this disclosure was inadequate since NorthWestern knew at that time that Expanets' bad debt reserve was materially insufficient.

19. In December 2002, NorthWestern announced that it anticipated that Expanets would take substantial charges in the fourth quarter relating to Expanets' uncollectible accounts receivable. In April 2003, NorthWestern restated its Forms 10-Q for the first three quarters of 2002 and increased Expanets' bad debt reserve for each of these periods by approximately $5.2 million, $5.1 million, and $6.3 million, respectively.

20. As a result of its improper accounting for uncollectible accounts receivable, NorthWestern overstated its income from continuing operations by approximately 16%, 19%, and 39% for the first three quarters of 2002, respectively, as reported in its Forms 10-Q and press

releases attached to Forms 8-K. Moreover, in its segment reporting for Expanets, NorthWestern understated Expanets' operating loss by approximately 66% for the first quarter of 2002, and overstated Expanets' operating income by approximately 86% and 270%, respectively, for the second and third quarters of 2002.

Adjustments to Customer Bills

21. As a result of the inaccurate customer bills generated by the EXPERT system, Expanets issued partial credits to affected customers. Expanets recorded these credits as "billing adjustments," which reduced both its revenue and income in the current period. Since Expanets credited customer accounts in periods after it initially recognized revenue from a transaction, Expanets maintained a "billing adjustment reserve" for anticipated credits to customer accounts. Expanets calculated its billing adjustment reserve based on the revenue it billed, its actual billing adjustments during the reporting period, and its evaluation of the aggregate accuracy of its customer bills.

22. Because EXPERT generated a significant number of inaccurate and incomplete customer bills in the first quarter of 2002, Expanets' billing adjustments in the first quarter of 2002 surpassed projected levels of approximately $2 million per month and reached more than $3 million for March 2002. During the first quarter of 2002, Expanets also internally forecasted that EXPERT's billing accuracy problems would continue for several months. Still, Expanets increased its billing adjustment reserve by a net of only approximately $1.5 million in the first quarter of 2002.

23. As EXPERT billings problems persisted during the second quarter of 2002, Expanets' billing adjustments significantly exceeded originally-projected levels and reached approximately $6 million for the month of June 2002. Expanets estimated that its billing adjustments would be $13 million higher than it had originally forecasted for the remainder of the year. However, Expanets did not increase its billing adjustment reserve to comport with these internal forecasts. Instead, Expanets reduced its billing adjustment reserve by $2.3 million during the second quarter, thereby increasing its operating income by the same amount.

24. For the third quarter of 2002, Expanets' billing adjustments totaled more than $22 million, which again significantly exceeded its original and revised projections. Expanets further estimated that, due to a planned correction of a certain category of customer bills, its billing adjustments for the fourth quarter would exceed its revised estimates by an additional $3.4 million. However, Expanets again did not increase its billing adjustment reserve. Instead, it reduced this reserve by $4 million during the third quarter, which increased Expanets' operating income by the same amount.

25. In December 2002, NorthWestern announced that it anticipated that Expanets would take substantial charges in the fourth quarter relating to Expanets' billing adjustments. In its April 2003 restatements for the first three quarters of 2002, NorthWestern acknowledged that it had understated its billing adjustment reserve in each of these quarters, and as a result, the company

reduced reported revenues and income by approximately $18.3 million, $10.1 million, and $5.4 million, respectively.

26. As a result of its improper accounting for billing adjustments, NorthWestern overstated its income from continuing operations by approximately 98%, 46%, and 31% for the first three quarters of 2002, respectively, as reported in its Forms 10-Q and press releases attached to Forms 8-K. In its segment reporting for Expanets, NorthWestern understated Expanets' operating loss by approximately 87% for the first quarter of 2002, and overstated Expanets' operating income by approximately 1094% and 164%, respectively, for the second and third quarters of 2002. NorthWestern also did not disclose in any of its filings for the first three quarters of 2002 that losses resulting from billing adjustments were probable or reasonably possible.

The Quality of Expanets' Income

Reserve Reductions

27. During the first three quarters of 2002, Expanets reduced amounts it had recorded in at least fourteen of the reserve accounts it maintained on its balance sheet, including the billing adjustments reserve account discussed above. These reductions materially increased Expanets' and NorthWestern's income.

28. In the first quarter of 2002, $2.6 million of Expanets' income was derived from reserve reductions. This amount reduced by approximately 50% Expanets' reported segment operating loss of approximately $2.7 million and represented approximately 7% of NorthWestern's reported income from continuing operations for that quarter.

29. In the second quarter of 2002, $8.8 million of Expanets' income was derived from reserve reductions. This amount represented approximately 80% of Expanets' reported segment operating income of $11 million and approximately 27% of NorthWestern's income from continuing operations for that quarter.

30. In the third quarter of 2002, $27 million of Expanets' income was derived from reserve reductions. With this income, Expanets was able to report $8.7 million of operating income rather than a substantial operating loss. In addition, with this income, NorthWestern was able to report $14.6 million of income from continuing operations for that quarter rather than an operating loss.

31. NorthWestern's Forms 10-Q for the first three quarters of 2002 did not disclose the material impact that these reserve reductions had on the reported results of operations of Expanets and NorthWestern during these periods. NorthWestern did not disclose the material impact of these reserve reductions until April 2003 when it restated its Forms 10-Q for the first three quarters of 2002.

Unusual Transactions

32. In conjunction with Expanets' acquisition of certain assets of a competitor, Expanets agreed that, in exchange for payments from the competitor, Expanets would not solicit specific business of the competitor's customers. Expanets' competitor was obligated to make these "non-compete" type of payments to Expanets until March 2005. These payments were not characteristic of Expanets' regular operations and therefore represented unusual transactions.

33. In the first quarter of 2002, NorthWestern reported in its segment disclosures that Expanets had an operating loss of approximately $2.7 million. Approximately $9.3 million of Expanets' income came from the non-compete payments. The $9.3 million also represented approximately 25% of NorthWestern's consolidated income from continuing operations for the quarter.

34. In the second quarter of 2002, NorthWestern reported in its segment disclosures that Expanets had operating income of approximately $11 million. Approximately $10 million of Expanets' income came from the non-compete payments. The $10 million also represented approximately 31% of NorthWestern's consolidated income from continuing operations for the quarter.

35. In the third quarter of 2002, NorthWestern reported in its segment disclosures that Expanets had operating income of approximately $8.7 million. Approximately $15.3 million of Expanets' income came from the non-compete payments. The $15.3 million also represented approximately 68% of NorthWestern's consolidated income from continuing operations for the quarter.

36. NorthWestern's Forms 10-Q for the first three quarters of 2002 did not disclose Expanets' receipt of these unusual non-compete payments and their material effects on Expanets' and NorthWestern's income. NorthWestern did not disclose the existence of these non-compete payments or their effect until it filed its 2002 Form 10-K and restated its 2002 Forms 10-Q in April 2003.

NorthWestern's Intercompany Advances to Expanets and Blue Dot

37. EXPERT's inability to generate any customer bills in late 2001 and early 2002 and other billing problems that followed caused Expanets' cash flow from operations during the first quarter of 2002 to be a deficit of approximately $68.7 million. As a result, NorthWestern provided Expanets with significant intercompany advances during the first quarter of 2002 to enable Expanets to pay operating and other expenses, including a scheduled amount on a third-party credit facility. By the end of the first quarter of 2002, NorthWestern's intercompany advances to Expanets totaled $63.3 million.

38. During the second quarter of 2002, EXPERT's continuing billing and collections problems caused Expanets' cash collections to lag significantly behind expected levels. NorthWestern therefore provided Expanets with additional intercompany advances of

approximately $50 million to help Expanets pay operating expenses and another scheduled amount on a third-party credit facility. By the end of the second quarter, NorthWestern's intercompany advances to Expanets totaled $113.4 million.

39. Similarly, during the first quarter of 2002, NorthWestern provided Blue Dot with approximately $21 million in intercompany advances so that Blue Dot could pay off a large credit facility and operating expenses when due. NorthWestern's outstanding intercompany advances to Blue Dot totaled approximately $37.1 million at the end of the first quarter of 2002.

40. In the second quarter of 2002, Blue Dot paid back some of the cash advanced by NorthWestern with proceeds from a one-time sale and leaseback transaction. Nevertheless, NorthWestern's outstanding intercompany advances to Blue Dot still totaled approximately $22.8 million at the end of that quarter.

41. NorthWestern's intercompany advances to Expanets and Blue Dot demonstrated that these businesses were continuing to require further investments from the parent company, rather than providing cash to the consolidated entity. NorthWestern's need to advance funds to Expanets and Blue Dot was information that was necessary to understand NorthWestern's financial condition and was reasonably likely to impact NorthWestern's liquidity.

42. NorthWestern's Form 10-Q for the first quarter of 2002 did not disclose NorthWestern's intercompany advances to Expanets or Blue Dot, or the significance of those advances. NorthWestern disclosed in its Form 10-Q for the second quarter of 2002 that it made intercompany advances to Expanets. However, NorthWestern still did not disclose its intercompany advances to Blue Dot or any information about the significance of the intercompany advances to either subsidiary. NorthWestern did not disclose the existence and amount of its intercompany advances until September 2002.

Allocation of Losses to Blue Dot Minority Interests

43. When Blue Dot acquired other businesses, it paid the former owners in part with Blue Dot common stock. As a result of these transactions, the former owners held minority interests in Blue Dot. NorthWestern allocated a portion of Blue Dot's losses to these minority interests, which had the effect of increasing NorthWestern's consolidated income from continuing operations. This accounting treatment was proper only to the extent that the losses applicable to the Blue Dot minority interest did not exceed the minority interest in the equity capital of Blue Dot.

44. Before it filed its financial statements for the second quarter of 2002, NorthWestern received a third-party appraisal of Blue Dot for the purpose of assessing Blue Dot's enterprise value. Based on the total value of the Blue Dot entity as reflected in the appraisal, Blue Dot's common stock was worthless.

45. Despite this information, in its financial statements for the second quarter of 2002, NorthWestern allocated $8.1 million of Blue Dot's losses to minority interests based on stock issued for acquisitions Blue Dot made that quarter. In addition, NorthWestern failed to disclose in

its second quarter Form 10-Q the material effects of the decrease in value of Blue Dot common stock, or any uncertainties about NorthWestern's ability to allocate losses to Blue Dot minority interests.

46. Because of its improper allocation of losses to minority interests, NorthWestern reported income from continuing operations of approximately $20.9 million rather than $12.8 million, an overstatement of approximately 63%, in its Form 10-Q for the second quarter of 2002 and a press release attached to a Form 8-K. NorthWestern reversed its allocation of losses to Blue Dot's minority interests when it restated its second quarter 2002 Form 10-Q in April 2003.

The Colstrip Utility Asset Sale

47. In February 2002, when NorthWestern purchased Montana Power, NorthWestern became the successor-in-interest to a contract for the sale of certain assets known as the "Colstrip" transmission assets ("Colstrip assets"). The contract called for a payment of approximately $97 million to NorthWestern upon the satisfaction of certain conditions. During the second quarter of 2002, NorthWestern announced that it expected to collect the proceeds from the sale of the Colstrip assets by June or July 2002.

48. Throughout 2002, the sale of the Colstrip assets was significant to NorthWestern because it would have generated significant cash for the company and enhanced its liquidity position. Accordingly, analysts and rating agencies tracked the status of the sale.

49. Between May and July 2002, the other party to the Colstrip assets sale contract repeatedly informed NorthWestern that it would not close the sale until the parties were able to resolve other claims. On August 5, 2002, NorthWestern filed but did not serve a complaint against this party in a Montana State court.

50. NorthWestern's Form 10-Q for the second quarter of 2002 did not disclose the Colstrip asset sale dispute and its potential impact on NorthWestern's financial condition, including its impact on NorthWestern's liquidity. On September 4, 2002, NorthWestern served its complaint on the other party to the Colstrip sale and subsequently disclosed the existence of its lawsuit in its third quarter Form 10-Q. In May 2005, NorthWestern settled the lawsuit by agreeing to retain the Colstrip assets in exchange for, among other things, a $9 million payment from the other party.

Violations

51. Sections 13(a) and 13(b)(2)(A) of the Exchange Act and Rules 12b-20, 13a-11, and 13a-13 require issuers to make and keep accurate books, records, and accounts, to file quarterly and current reports with the Commission, and to keep reported information current and not misleading. As a result of the conduct described above, NorthWestern violated Sections 13(a) and 13(b)(2)(A) of the Exchange Act and Rules 12b-20, 13a-11, and 13a-13 thereunder.

52. Section 13(b)(2)(B) of the Exchange Act requires issuers to devise and maintain a system of internal accounting controls sufficient to provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles. As a result of the conduct described above, NorthWestern violated Section 13(b)(2)(B) of the Exchange Act.

IV.

In determining to accept the Offer, the Commission considered remedial acts promptly undertaken by Respondent and cooperation afforded the Commission staff.

V.

In view of the foregoing, the Commission deems it appropriate to impose the sanctions agreed to in Respondent NorthWestern's Offer.

Accordingly, it is hereby ORDERED that Respondent cease and desist from committing or causing any violations and any future violations of Sections 13(a), 13(b)(2)(A) and 13(b)(2)(B) of the Exchange Act and Rules 12b-20, 13a-11, and 13a-13 thereunder.

By the Commission.

Nancy M. Morris
Secretary

SENATE NATURAL RESOURCES
EXHIBIT NO. 19
DATE 3-30-07
BILL NO. HB25

Amendments to House Bill No. 25
2nd Reading Copy
Requested by ~~Representative Dave Gallik~~ COMMISSIONER BRAD MOLNAR
For the ~~House Committee of the Whole~~ SENATE NATURAL RESOURCES COMMITTEE

Prepared by Todd Everts
March 30, 2007 (11:29am)

1. Page 18, line 21.
Following: "(1)"
Insert: "(a)"
Strike: "A"
Insert: "Except as provided for in subsection (1)(b), a"

2. Page 19.
Following: line 3
Insert: "(b) (i) A public utility referred to subsection (1)(a) shall include in its rate base currently owned noncontracted generation assets, including any equity or leased interest in currently owned generation assets, ~~prior to applying to the commission for preapproval of any new generation assets~~.

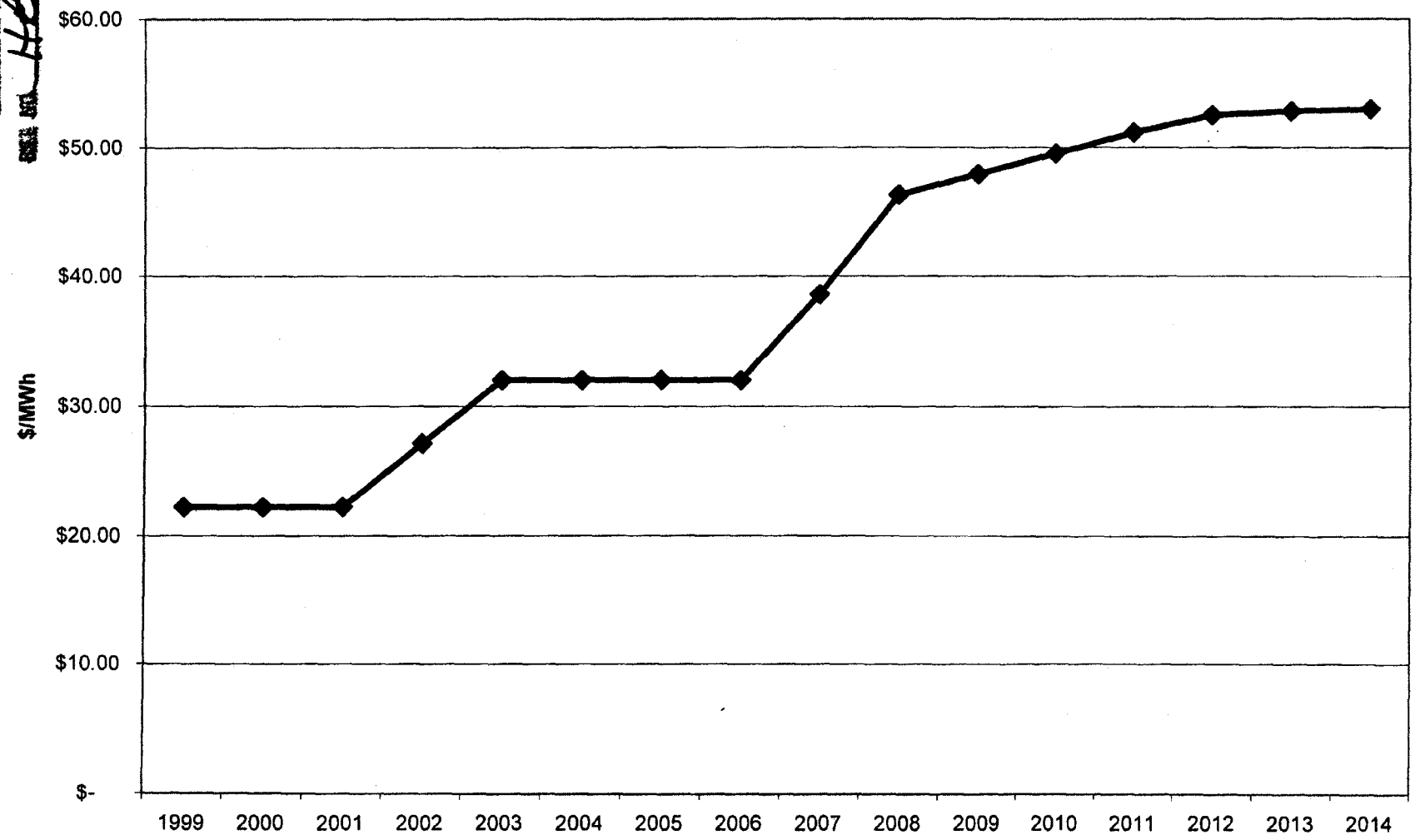
(ii) As currently owned contracted generation assets become available on the termination of any existing contract or contracts, the public utility referred to subsection (1)(a) shall include those generation assets in its rate base, ~~prior to applying to the commission for preapproval~~ of any new generation ~~assets~~.

(iii) Nothing is this subsection (1)(b) impairs existing contractual obligations."

- END -

(iii) REFERENCED UTILITY SHALL USE ALL PROCESSES DEEMED BY THE PSC AND MCC TO BUY OUT EXISTING CONTRACTS IN COLSTRIP 4 GENERATION

MONTANA PUBLIC SERVICE COMMISSION
EXHIBIT NO. 20
DATE 3-30-07
DOCKET NO. 4825



Bob Ranek
222-0558
3/30/07

MINUTES

MONTANA SENATE
60th LEGISLATURE - REGULAR SESSION

COMMITTEE ON NATURAL RESOURCES AND ENERGY

Call to Order: By **CHAIRMAN GREG LIND**, on March 31, 2007 at 10:30 A.M., in Room 422 Capitol.

ROLL CALL

Members Present:

Sen. Greg Lind, Chairman (D)
Sen. Aubyn Curtiss (R)
Sen. Kelly Gebhardt (R)
Sen. Dan Harrington (D)
Sen. Christine Kaufmann (D)
Sen. Gary L. Perry (R)
Sen. Bill Tash (R)
Sen. Mitch Tropila (D)
Sen. David E. Wanzenried (D)

Members Excused: None.

Members Absent: None.

Staff Present: Claudia Johnson, Committee Secretary
Joe Kolman, Legislative Branch

Audio Committees: These minutes are in outline form only. They provide a list of participants and a record of official action taken by the committee. The link to the audio recording of the meeting is available on the Legislative Branch website.

Committee Business Summary:

Hearing & Date Posted:	None.
Executive Action:	HB 25, HB 584, HB 460, HB 681, HB 689, HJ 8, HB 36, HB 205, HB 328, HB 405, HB 383, HB 715, HJ 13, HJ 31, HB 25, HB 611, HB 728

00:01:38 Chairman Lind

Discussion:

00:03:19 Sen. Gebhardt to Sen. Lind

00:04:23 Sen. Lind

00:07:56 Sen. Lind to Sonja Lee, LSD

00:08:12 Sonja Lee, LSD

00:13:29 Sen. Tash

00:14:59 Sen. Perry

00:17:24 Sen. Curtiss

00:18:35 Sen. Kaufmann

00:19:21 Sen. Harrington

00:22:02 Sen. Tropila

00:23:26 Sen. Lind

00:24:50 Sen. Tropila

00:25:12 Sen. Gebhardt

00:26:32 Sen. Lind

00:26:37 Sen. Perry

EXECUTIVE ACTION ON HB 25

00:26:46 **Motion: SEN. GEBHARDT moved that HB 25 BE CONCURRED IN.**

Discussion:

00:27:11 Sen. Gebhardt to Brad Molnar, Public Service Commission (PSC)

00:29:16 Sen. Tash to Greg Jergeson, PSC

00:30:49 Sen. Tash to John Fitzpatrick, Northwestern Energy (NWE)

00:37:29 Sen. Lind to John Fitzpatrick, NWE

00:37:53 Sen. Gebhardt to John Fitzpatrick, NWE

00:39:57 Sen. Lind to John Fitzpatrick, NWE

00:42:10 Sen. Lind to Greg Jergeson, PSC

00:47:23 Sen. Tropila to David Hoffman, PPL Montana, LLC

00:49:08 Sen. Lind

00:49:21 Sen. Tash

00:50:30 Sen. Gebhardt

00:51:28 Sen. Tropila

00:51:38 **Motion: SEN. KAUFMANN moved that AMENDMENT HB002509.ASL BE ADOPTED.**

Discussion:

00:52:04 Sen. Perry

00:52:39 Sen. Lind

00:52:43 Sen. Curtiss

00:53:23 Sen. Kaufmann

00:54:42 Sen. Perry to Sen. Kaufmann

00:55:02 Sen. Harrington

00:55:44 Sen. Lind

00:55:55 **Vote: Motion that AMENDMENT HB002509.ASL BE ADOPTED failed 3-6 by roll call vote with SEN. KAUFMANN, SEN. TROPILA, and SEN. WANZENRIED voting aye.**

00:55:75 **Substitute Motion/Vote: SEN. TASH made a substitute motion that HB 25 BE TABLED. Substitute motion failed 3-6 by roll call vote with SEN. CURTISS, SEN. PERRY, and SEN. TASH voting aye.**

00:57:51 **Motion: SEN. GEBHARDT moved that HB 25 BE CONCURRED IN.**

Discussion:

00:58:04 Sen. Kaufmann

EXHIBIT(nas69a01)

00:58:58 Sen. Harrington

00:59:55 Sen. Lind to Sen. Kaufmann

01:00:35 Sen. Gebhardt

01:02:07 Sen. Lind

01:03:00 Sen. Kaufmann

01:04:25 Sen. Gebhardt

01:05:17 Sen. Lind

EXHIBIT(nas69a02)

01:05:48 **Motion: SEN. LIND moved that AMENDMENT HB002503.ASL BE ADOPTED.**

Discussion:

01:06:14 Sonja Lee, LSD

01:09:12 Sen. Lind

01:11:40 Sen. Gebhardt to Sen. Lind

01:14:59 Sen. Tash to Sen. Lind

01:15:46 **Sen. Lind withdrew his motion on AMENDMENT HB002503.ASL.**

01:16:05 Sen. Perry

01:17:57 **Motion: SEN. KAUFMANN moved that AMENDMENT HB002503.ASL BE ADOPTED.**

Discussion:

01:18:34 Sen. Kaufmann to John Fitzpatrick, NWE

01:21:08 Sen. Kaufmann

01:22:07 Sen. Tropila

01:22:33 Sen. Harrington

01:23:06 **Motion/Vote: SEN. HARRINGTON called the question on AMENDMENT HB002503.ASL BE ADOPTED. Motion carried 5-4 by roll call vote with SEN. CURTISS, SEN. GEBHARDT, SEN. PERRY, and SEN. TASH voting no.**

01:25:10 Break.

02:37:36 Back from break.

02:37:52 **Motion: SEN. TROPILA moved that AMENDMENT HB002512.ATE BE ADOPTED.**

EXHIBIT(nas69a03)

Discussion:

02:39:29 Sen. Gebhardt

02:40:57 **Motion/Vote: SEN. GEBHARDT CALLED THE QUESTION ON AMENDMENT HB002512.ATE. Motion failed 3-6 by roll call vote with SEN. KAUFMANN, SEN. LIND, and SEN. TROPILA voting aye.**

Discussion:

02:43:01 Sonja Lee, LSD

EXHIBIT(nas69a04)

02:43:58 **Motion/Vote: SEN. GEBHARDT moved that AMENDMENT HB002510.ASL BE ADOPTED. Motion carried unanimously by voice vote. SEN. TASH, SEN. HARRINGTON, and SEN. WANZENRIED voted by proxy.**

Discussion:

02:45:07 Sen. Lind

02:45:29 **Motion: SEN. GEBHARDT moved that HB 25 BE CONCURRED IN AS AMENDED.**

Discussion:

02:45:56 Sen. Kaufmann to Russ Doty, Green Electric Buying Cooperatives (GEBC)

02:46:29 **Motion: SEN. LIND moved that AMENDMENT HB002506.ASL BE ADOPTED.**

EXHIBIT(nas69a05)

Discussion:

02:45:53 Sonja Lee, LSD

02:48:07 Sen. Lind to Sonja Lee, LSD

02:48:39 Sen. Lind to Russ Doty, GEBC

02:49:50 Sen. Gebhardt

02:50:51 Sen. Curtiss

02:51:17 Sen. Gebhardt

02:51:44 Sen. Lind

02:52:23 Sen. Gebhardt

02:52:48 **Motion/Vote: SEN. GEBHARDT CALLED THE QUESTION ON AMENDMENT HB002506.ASL. Motion failed 4-5 by roll call vote with SEN. HARRINGTON, SEN. KAUFMANN, SEN. LIND, and SEN. WANZENRIED voting aye.**

02:54:28 **Vote: Motion that HB 25 BE CONCURRED IN AS AMENDED carried 7-2 by roll call vote with SEN. CURTISS and SEN. TROPILA voting no.**

Refer to page 16 of the minutes for reconsideration of HB 25.

EXECUTIVE ACTION ON HB 584

02:56:45 **Motion: SEN. LIND moved that HB 584 BE CONCURRED IN.**

Discussion:

02:56:53 **Motion: SEN. LIND moved that AMENDMENT HB058401.AJK BE ADOPTED.**

SENATE NATURAL RESOURCES
EXHIBIT NO. 1
DATE 3-31-07
BILL NO. HB 25

Amendments to House Bill No. 25
3rd Reading Copy

Requested by Senator Christine Kaufmann

For the Senate Natural Resources and Energy Committee

Prepared by Sonja Lee
March 31, 2007 (9:04am)

1. Title, page 1, line 10 through line 11.
Strike: "CLARIFYING" on line 10 through "ASSETS;" on line 11 in their entirety

2. Title, page 1, line 12.
Following: "69-1-114,"
Insert: "69-1-402,"

3. Title, page 1, line 13.
Strike: "69-8-411, through "69-8-421,"

4. Title, page 1, line 15.
Following: "~~69-8-403,~~"
Insert: "69-8-401,"

5. Title, page 1, line 16.
Strike: "AND"
Following: "69-8-410,"
Insert: "69-8-419, 69-8-420, AND 69-8-421,"

6. Page 4, line 9.
Following: "69-3-204(2)"
Strike: ","
Strike: "69-8-421(9),"

7. Page 4, line 11 through line 12.
Strike: subsection (3) in its entirety

8. Page 4, line 13.
Insert: "Section 5. Section 69-1-402, MCA, is amended to read:

"69-1-402. Funding of department of public service regulation. (1) All fees collected under this section and any other fees~~, except as provided in 69-1-114(3),~~ must be deposited in an account in the state special revenue fund to the credit of the department. An appropriation to the department may consist of a base appropriation for regular operating expenses and a contingency appropriation for expenses due to an unanticipated caseload.

(2) In addition to all other licenses, fees, and taxes imposed by law, all regulated companies shall, within 30 days

after the close of each calendar quarter, pay to the department of revenue a fee based on a percentage of gross operating revenue reported pursuant to 69-1-223(2)(a), as determined by the department of revenue under 69-1-403.

(3) The amount of money that may be raised by the fee on the regulated companies during a fiscal year may not be increased, except as provided in 69-1-224(1)(c), from the amount appropriated to the department by the legislature for that fiscal year, including both base and contingency appropriations. Any additional money required for operation of the department must be obtained from other sources in a manner authorized by the legislature."

{*Internal References to 69-1-402:*
69-1-403x *69-1-403x*}"

Renumber: subsequent sections

9. Page 7, line 29 through page 8, line 1.
Strike: subsection (11) in its entirety
Renumber: subsequent subsections

10. Page 14, line 10.
Strike: "**environmentally preferred resources**"
Insert: "**optional supply product**"

11. Page 14, line 12 through line 17.
Strike: subsection (1) in its entirety
Insert: "(1) Any electricity supply resource included in the rate base must be used and useful as determined by the commission."

12. Page 16, line 17 through page 21, line 9.
Strike: section 11 through section 14 in their entirety
Renumber: subsequent sections

13. Page 24, line 23 through page 25, line 2.
Strike: section 18 through section 19 in their entirety
Renumber: subsequent sections

14. Page 25, line 6.
Following: "~~69-8-403,~~"
Insert: "69-8-401,"
Strike: "AND"
Following: "69-8-410,"
Insert: "69-8-419, 69-8-420, and 69-8-421,"

- END -

SENATE NATURAL RESOURCES
EXHIBIT NO. 2
DATE 3-31-07
BILL NO. HB 25

Amendments to House Bill No. 25
3rd Reading Copy

Requested by Senator Greg Lind

For the Senate Natural Resources and Energy Committee

Prepared by Sonja Lee
March 31, 2007 (10:46am)

1. Title, page 1, line 11.
Following: "RESOURCES;"
Insert: "REQUIRING THE COMMISSION TO ADDRESS CARBON OFFSETS IN THE APPROVAL PROCESS;"

2. Title, page 1, line 16.
Following: "MCA"
Insert: "; AND PROVIDING AN IMMEDIATE EFFECTIVE DATE"

3. Page 3, line 17.
Strike: "69-8-103(3)(b)"
Insert: "69-8-103(4)(b)"

4. Page 5.
Following: line 27
Insert: "(3) "Carbon offset provider" means a qualified third-party entity that arranges for projects or actions that either reduce carbon dioxide emissions or that increase the absorption of carbon dioxide."
Renumber: subsequent subsections

5. Page 6.
Following: line 3
Insert: "(5) "Cost-effective carbon offsets" means any combination of certified actions taken to reduce carbon dioxide emissions, which collectively do not increase the cost of electricity produced annually on a per-megawatt-hour basis by more than 2.5%, including:
(a) actions undertaken by the applicant that increase the absorption of carbon dioxide from a facility or equipment used to generate electricity; or
(b) actions by a carbon offset provider on behalf of the applicant."
Renumber: subsequent subsections

6. Page 17, line 20.
Strike: "DECEMBER 31, 2007"
Insert: "March 31, 2008"

7. Page 19, line 12.

Following: "(4)"
Insert: "(a)"
Strike: "THE"
Insert: "Except as provided in subsections (4)(b) through (4)(d), the"

8. Page 19.
Following: line 16
Insert: "(b) If an air quality permit pursuant to Title 75, chapter 2, is required for a new electrical generation resource or a modification to an existing resource, the commission shall hold the public hearing on the application for approval at least 30 days after the issuance of the final air quality permit.

(c) If a final air quality permit is not issued within the time limit pursuant to subsection (4)(a), the commission shall extend the time limit in order to comply with subsection (4)(b).

(d) The commission may extend the time limit for issuing an order for an additional 60 days following the hearing pursuant to subsection (4)(b)."

9. Page 20.
Following: line 7
Insert: "(e) When issuing an order for the acquisition of an equity interest or lease in a facility or equipment that is constructed after January 1, 2007, and that is used to generate electricity that is primarily fueled by natural or synthetic gas, the commission shall require the applicant to implement cost-effective carbon offsets. Expenditures required for cost-effective carbon offsets pursuant to this subsection (6)(e) are fully recoverable in rates. By March 31, 2008, the commission shall adopt rules for the implementation of this subsection (6)(e)."
Renumber: subsequent subsections

10. Page 20.
Following: line 20
Insert: "(8) Until the state or federal government has adopted uniformly applicable statewide standards for the capture and sequestration of carbon dioxide, the commission may not approve an application for the acquisition of an equity interest or lease in a facility or equipment used to generate electricity that is primarily fueled by coal and that is constructed after January 1, 2007, unless the facility or equipment captures and sequesters a minimum of 50% of the carbon dioxide produced by the facility."
Renumber: subsequent subsections

11. Page 21, line 8.
Strike: "DECEMBER 31, 2007"

Insert: "March 31, 2008"

12. Page 25, line 14.
Insert: "NEW SECTION. **Section 23. Effective date.** [This act] is effective on passage and approval."

- END -

SENATE NATURAL RESOURCES
EXHIBIT NO. 3
DATE 3-31-07
BILL NO. HB 25

Amendments to House Bill No. 25
3rd Reading Copy

Requested by Senator Mitch Tropila

For the Senate Natural Resources and Energy Committee

Prepared by Todd Everts
March 30, 2007 (12:37pm)

1. Page 18, line 21.
Following: "(1)"
Insert: "(a)"
Strike: "A"
Insert: "Except as provided in subsection (1)(b), a"

2. Page 19.
Following: line 3
Insert: "(b) (i) A public utility referred to subsection (1)(a) shall include in its rate base currently owned noncontracted generation assets, including any equity or leased interest in currently owned generation assets, prior to applying to the commission for preapproval of any new generation assets.

(ii) As currently owned contracted generation assets become available on the termination of any existing contract or contracts, the public utility referred to subsection (1)(a) shall include those generation assets in its rate base prior to applying to the commission for preapproval of any new generation assets.

(iii) Nothing is this subsection (1)(b) impairs existing contractual obligations."

- END -

EXHIBIT NO. 4
DATE 3-31-07
SB NO. HB25

Amendments to House Bill No. 25
3rd Reading Copy

For the Senate Natural Resources and Energy Committee

Prepared by Sonja Lee
March 30, 2007 (11:02am)

1. Title, page 1, line 12.
Following: "69-8-311,"
Insert: "69-8-402,"

2. Page 15, line 16.
Insert: "Section 10. Section 69-8-402, MCA, is amended to read:
"69-8-402. Universal system benefits programs. (1) Universal system benefits programs are established for the state of Montana to ensure continued funding of and new expenditures for energy conservation, renewable resource projects and applications, and low-income energy assistance.

(2) Beginning January 1, 1999, 2.4% of each utility's annual retail sales revenue in Montana for the calendar year ending December 31, 1995, is established as the initial funding level for universal system benefits programs. To collect this amount of funds on an annualized basis in 1999, the commission shall establish rates for utilities subject to its jurisdiction and the governing boards of cooperatives shall establish rates for the cooperatives. These universal system benefits charge rates must remain in effect through December 31, 2009.

(a) The recovery of all universal system benefits programs costs imposed pursuant to this section is authorized through the imposition of a universal system benefits charge assessed at the meter for each local utility system customer as provided in this section.

(b) A utility must receive credit toward annual funding requirements for the utility's internal programs or activities that qualify as universal system benefits programs, including those amortized or nonamortized portions of expenditures for the purchase of power that are for the acquisition or support of renewable energy, conservation-related activities, or low-income energy assistance, and for large customers' programs or activities as provided in subsection (7). The department of revenue shall review claimed credits of the utilities and large customers pursuant to 69-8-414.

(c) A ~~utility's distribution services provider~~ utility at which the sale of power for final end use occurs is the utility that receives credit for the universal system benefits programs expenditure.

(d) A customer's ~~distribution services provider~~ utility shall collect universal system benefits funds less any allowable credits.

(e) For a utility to receive credit for low-income-related expenditures, the activity must have taken place in Montana.

(f) If a utility's or a large customer's credit for internal activities does not satisfy the annual funding provisions of subsection (2), then the utility shall make a payment to the universal system benefits fund established in 69-8-412 for any difference.

(3) Cooperative utilities may collectively pool their statewide credits to satisfy their annual funding requirements for universal system benefits programs and low-income energy assistance.

(4) A utility's transition plan must describe how the utility proposes to provide for universal system benefits programs, including the methodologies, such as cost-effectiveness and need determination, used to measure the utility's level of contribution to each program.

(5) A utility's minimum annual funding requirement for low-income energy and weatherization assistance is established at 17% of the utility's annual universal system benefits funding level and is inclusive within the overall universal system benefits funding level.

(a) A utility must receive credit toward the utility's low-income energy assistance annual funding requirement for the utility's internal low-income energy assistance programs or activities.

(b) If a utility's credit for internal activities does not satisfy its annual funding requirement, then the utility shall make a payment for any difference to the universal low-income energy assistance fund established in 69-8-412.

(6) An individual customer may not bear a disproportionate share of the local utility's funding requirements, and a sliding scale must be implemented to provide a more equitable distribution of program costs.

(7) (a) A large customer:

(i) shall pay a universal system benefits programs charge with respect to the large customer's qualifying load equal to the lesser of:

(A) $500,000, less the large customer credits provided for in this subsection (7); or

(B) the product of 0.9 mills per kilowatt hour multiplied by the large customer's total kilowatt hour purchases, less large customer credits with respect to that qualifying load provided for in this subsection (7);

(ii) must receive credit toward that large customer's universal system benefits charge for internal expenditures and activities that qualify as a universal system benefits programs expenditure, and these internal expenditures must include but not be limited to:

(A) expenditures that result in a reduction in the consumption of electrical energy in the large customer's

facility; and

(B) those amortized or nonamortized portions of expenditures for the purchase of power at retail or wholesale that are for the acquisition or support of renewable energy or conservation-related activities.

(b) Large customers making these expenditures must receive a credit against the large customer's universal system benefits charge, except that any of those amounts expended in a calendar year that exceed that large customer's universal system benefits charge for the calendar year must be used as a credit against those charges in future years until the total amount of those expenditures has been credited against that large customer's universal system benefits charges.

(8) A public utility shall prepare and submit an annual summary report of the public utility's activities relating to all universal system benefits programs to the commission, the department of revenue, and the energy and telecommunications interim committee provided for in 5-5-230. A cooperative utility shall prepare and submit annual summary reports of activities to the cooperative utility's respective local governing body, the statewide cooperative utility office, and the energy and telecommunications interim committee. The statewide cooperative utility office shall prepare and submit an annual summary report of the activities of individual cooperative utilities, including a summary of the pooling of statewide credits, as provided in subsection (3), to the department of revenue and the energy and telecommunications interim committee. The annual report of a public utility or of the statewide cooperative utility office must include but is not limited to:

(a) the types of internal utility and customer programs being used to satisfy the provisions of this chapter;

(b) the level of funding for those programs relative to the annual funding requirements prescribed in subsection (2); and

(c) any payments made to the statewide funds in the event that internal funding was below the prescribed annual funding requirements.

(9) A utility or large customer filing for a credit shall develop and maintain appropriate documentation to support the utility's or the large customer's claim for the credit.

(10) (a) A large customer claiming credits for a calendar year shall submit an annual summary report of its universal system benefits programs activities and expenditures to the department of revenue and to the large customer's utility. The annual report of a large customer must identify each qualifying project or expenditure for which it has claimed a credit and the amount of the credit. Prior approval by the department of revenue or the utility is not required, except as provided in subsection (10)(b).

(b) If a large customer claims a credit that the department of revenue disallows in whole or in part, the large customer is

financially responsible for the disallowance. A large customer and the large customer's utility may mutually agree that credits claimed by the large customer be first approved by the utility. If the utility approves the large customer credit, the utility may be financially responsible for any subsequent disallowance."

{*Internal References to 69-8-402:*
69-8-201A *69-8-201A* *69-8-311A* *69-8-412X*
69-8-414X *69-8-414X*}"

- END -

SENATE NATURAL RESOURCES
EXHIBIT NO. 5
DATE 3-31-07
BILL NO. HB 25

Amendments to House Bill No. 25
3rd Reading Copy

Requested by Senator David Wanzenried

For the Senate Natural Resources and Energy Committee

Prepared by Sonja Lee
March 30, 2007 (7:39am)

1. Title, page 1, line 11.
Following: "ASSETS;"
Insert: "REQUIRING THE PUBLIC SERVICE COMMISSION TO ESTABLISH TARIFFS;"

2. Page 11, line 7.
Following: "**exemption**"
Insert: "**-- tariffs**"

3. Page 13, line 14.
Following: "KILOWATTS"
Strike: "AND"
Insert: "that is not purchasing electricity from a public utility on [the effective date of this act] or a small customer of a buying cooperative pursuant to Title 35, chapter 19,"

4. Page 13, line 15.
Following: "SUPPLIER"
Insert: "or a buying cooperative established pursuant to Title 35, chapter 19"
Following: "CUSTOMER"
Insert: "or small customer of a buying cooperative pursuant to Title 35, chapter 19"

5. Page 13, line 18.
Following: "(B)"
Strike: "A"
Insert: "Except as provided in subsection (3), a"

6. Page 13.
Following: line 20
Insert: "(3) Subject to the tariffs established pursuant to subsection (6) and notwithstanding any other provisions of this section, a small customer, as defined in 35-19-102, may:
(a) choose to purchase electricity from a buying cooperative pursuant to Title 35, chapter 19; and
(b) subsequently purchase electricity from a public utility."
Renumber: subsequent subsections

7. Page 13, line 21.
Following: "AFFECTS"
Strike: "A RETAIL CUSTOMER'S"
Insert: "the"
Following: "OBLIGATIONS"
Insert: "of a customer pursuant to subsection (3) or the rights and obligations of a retail customer"

8. Page 13, line 27.
Strike: "(4)(B)"
Insert: "(5)(b)"

9. Page 14, line 1.
Strike: "(4)(A)"
Insert: "(5)(a)"

10. Page 14.
Following: line 4
Insert: "(6) Upon the request of an electricity supplier or a buying cooperative formed pursuant to Title 35, chapter 19, the commission shall prepare the following tariffs for public utilities:

(a) a nondiscriminatory, cost-based tariff indicating the costs that a public utility will incur if transmission and distribution services are provided to another electricity supplier;

(b) a nondiscriminatory, cost-based reentry tariff for the relevant customer class to defray the costs of a customer returning to a public utility, with the commission taking into account, among other things, the benefit to the public utility customers of having increased load from the additional customer to defray costs on all of its systems; and

(c) a nondiscriminatory, cost-based tariff for a customer class to defray the unrecovered, embedded costs of customers that leave the utility. The commission shall, in making a decision on a tariff, take into account the following:

(i) additional demands on the energy supply system that can defray the loss of customers;

(ii) the extent to which the customer leaving the energy supply system will enable the utility to purchase less power, decreasing spot-market or short-term contract purchases;

(iii) the benefit to the utility of not needing to construct additional generation facilities; and

(iv) any other factors that the commission considers necessary."

11. Page 16, line 24.
Strike: the first "and"
Insert: ", buying cooperatives formed pursuant to Title 35,

chapter 19, and"

12. Page 16, line 26.
Following: "identified in"
Insert: "35-19-102 and"

13. Page 16, line 27.
Following: "and (2)"
Insert: "and small customers pursuant to 35-19-102"

- END -

MINUTES

MONTANA HOUSE OF REPRESENTATIVES
60th LEGISLATURE - REGULAR SESSION

CONFERENCE COMMITTEE ON SENATE AMENDMENTS TO HOUSE BILL 25

Call to Order: By **SEN. JESSE LASLOVICH**, on April 16, 2007 at 4:15 P.M., in Room 172 Capitol.

ROLL CALL

Members Present:
Rep. Alan Olson, (Sponsor)(R)
Sen. John Esp (R)
Rep. Michael Lange (R)
Sen. Jesse Laslovich (D)(Chairman)(D)
Sen. Don Ryan (D)
Rep. Bill Thomas (D)

Members Excused: None

Members Absent: None

Staff Present: Todd Everts, Legislative Branch
Cindy Peterson, Committee Secretary

Audio Committees: These minutes are in outline form only. They provide a list of participants and a record of official action taken by the committee. The link to the audio recording of the meeting is available on the Legislative Branch website.

Committee Business Summary:
Executive Action: HB 25

EXECUTIVE ACTION ON HB 25

00:00:42 Sen. Ryan

00:01:29 **Motion**: Rep. Olson moved that HB 25 **BE AMENDED.** **EXHIBIT(cch80hb0025a01)**

Discussion:

00:01:40 Rep. Olson
00:01:57 Sen. Ryan
00:02:38 Rep. Olson withdrew his motion

00:02:44 **Motion**: Rep. Thomas moved that HB 25 **BE AMENDED.** **EXHIBIT(cch80hb0025a02)**

Discussion:

00:02:56 Rep. Thomas
00:03:18 Sen. Ryan
00:03:32 Rep. Olson
00:04:09 Sen. Ryan
00:05:41 Rep. Olson

00:07:01 **Vote**: Motion failed 2-4 by roll call vote with Rep. Thomas and Sen. Ryan voting aye.

00:07:38 **Motion**: Rep. Thomas moved HB 25 **BE AMENDED.** **EXHIBIT(cch80hb0025a03)**

Discussion:

00:07:53 Rep. Thomas
00:09:51 Rep. Olson
00:10:48 Sen. Ryan
00:14:54 Sen. Laslovich
00:15:36 Sen. Ryan
00:16:48 Rep. Olson

00:17:37 **Vote**: Motion failed 2-4 by roll call vote with Rep. Thomas and Sen. Ryan voting aye.

00:18:06 **Motion/Vote**: Rep. Olson moved that HB 25 **BE AMENDED** (Exhibit 1). Motion carried unanimously by roll call vote.

00:19:21 **Motion**: Rep. Olson moved that HB 25 **BE AMENDED.** **EXHIBIT(cch80hb0025a04)**

Discussion:

00:19:33 Rep. Olson
00:19:47 Rep. Lange

00:21:00 **Vote**: Motion carried 4-2 by roll call vote with Rep. Thomas and Rep. Ryan voting no.

00:21:08 Sen. Esp
00:21:35 Rep. Olson
00:21:50 Sen. Ryan
00:21:58 Rep. Olson
00:22:20 Sen. Ryan
00:22:48 Sen. Laslovich
00:23:40 Sen. Ryan
00:24:15 Sen. Laslovich
00:24:25 Sen. Ryan
00:24:51 Rep. Lange
00:25:35 Rep. Thomas
00:26:57 Rep. Olson
00:30:03 Sen. Esp

00:30:41 **Vote**: Conference Committee report **WAS ADOPTED** 4-2, by roll call vote with Rep. Thomas and Sen. Ryan voting no.

ADJOURNMENT

00:31:22 Adjourn at 4:46

SEN. JESSE LASLOVICH, Chairman

CINDY PETERSON, Secretary

Additional Exhibits:

EXHIBIT(cch80hb0025aad.pdf)

EXHIBIT 1
DATE 4-16-07
HB 25

Amendments to House Bill No. 25
Reference Copy

Requested by Representative Alan Olson

For the House Conference Committee

Prepared by Todd Everts
April 16, 2007 (8:40am)

1. Title, line 15.
Following: "MCA;"
Insert: "AND"

2. Title, line 17 through line 18.
Following: "MCA"
Strike: "; " on line 17 through "DATE" on line 18

3. Page 30, line 11.
Strike: section 24 in its entirety

- END -

EXHIBIT 2
DATE 4-16-07
HB 25

Amendments to House Bill No. 25
Reference Copy

Requested by Representative Bill Thomas

For the House Conference Committee

Prepared by Todd Everts
April 16, 2007 (1:44pm)

1. Title, line 18.
Strike: "AN IMMEDIATE"
Insert: "A DELAYED"

2. Page 30, line 11.
Strike: "ON PASSAGE AND APPROVAL"
Insert: "July 1, 2012"

- END -

EXHIBIT 3
DATE 4-16-07
HB 25

Amendments to House Bill No. 25
Reference Copy

Requested by Representative Bill Thomas

For the House Conference Committee

Prepared by Todd Everts
April 16, 2007 (1:44pm)

1. Title, line 18.
Strike: "AN IMMEDIATE"
Insert: "A DELAYED"

2. Page 30, line 11.
Strike: "ON PASSAGE AND APPROVAL"
Insert: "October 1, 2009"

- END -

EXHIBIT 4
DATE 4-16-07
HB 25

Amendments to House Bill No. 25
Reference Copy

Requested by Representative Alan Olson

For the House Conference Committee

Prepared by Todd Everts
April 16, 2007 (8:41am)

1. Page 25, line 16.
Following: "FACILITY."
Insert: "Carbon dioxide captured by a facility or equipment may be sequestered offsite from the facility or equipment."

- END -

HOUSE OF REPRESENTATIVES
Roll Call
Conference Committee on HB 25

DATE: April 16, 2007

NAME	PRESENT	ABSENT/ EXCUSED
REP. OLSON	✓	
REP. LANGE	✓	
REP. THOMAS	✓	
SEN. LASLOVICH	✓	
SEN. RYAN	✓	
SEN. ESP	✓	

CONFERENCE COMMITTEE
on Senate amendments to House Bill 25
Report No. 2, April 17, 2007

Mr. Speaker and Mr. President:

We, your Conference Committee met and considered Senate amendments to **House Bill 25** (reference copy -- salmon) and recommend this Conference Committee report be adopted.

For the House:

Rep. Alan Olson Vice Chair

Rep. Michael Lange

Rep. Bill Thomas

Amendment Coordinator

Chief Clerk of the House

For the Senate:

Sen. Jesse Laslovich Chair

Sen. Don Ryan

Sen. John Esp

And, recommend that **House Bill 25** (reference copy -- salmon) be amended as follows:

1. Title, line 15.
Following: "MCA;"
Insert: "AND"

2. Title, line 17 through line 18.
Following: "MCA"
Strike: ":" on line 17 through "DATE" on line 18

3. Page 25, line 16.
Following: "FACILITY."
Insert: "Carbon dioxide captured by a facility or equipment may

ADOPT **Amendment # HB 25-1**

REJECT KA 810938CC.hjd

be sequestered offsite from the facility or equipment."

4. Page 30, line 11.
Strike: section 24 in its entirety

- END -

Senate Conference Committee
on
HB 25

Roll Call Vote

DATE: 4-16-07 Exhibit 2

NAME	YES	NO
REP. OLSON		✓
REP. LANGE		✓
REP. THOMAS	✓	
SEN. LASLOVICH		✓
SEN. RYAN	✓	
SEN. ESP		✓

Senate Conference Committee
on
HB 25

Roll Call Vote

DATE: 4-16-07 Ex. 3

NAME	YES	NO
REP. OLSON		✓
REP. LANGE		✓
REP. THOMAS	✓	
SEN. LASLOVICH		✓
SEN. RYAN	✓	
SEN. ESP		✓
	2	-4

Senate Conference Committee
on
HB 25

Ex 1

Roll Call Vote

DATE: 4-16-07

NAME	YES	NO
REP. OLSON	✓	
REP. LANGE	✓	
REP. THOMAS	✓	
SEN. LASLOVICH	✓	
SEN. RYAN	✓	
SEN. ESP	✓	

Senate Conference Committee
on
HB 25

accept cc report

Roll Call Vote

DATE: 4-16-07

NAME	YES	NO
REP. OLSON	✓	
REP. LANGE	✓	
REP. THOMAS		✓
SEN. LASLOVICH	✓	
SEN. RYAN		✓
SEN. ESP	✓	
	✓	
	4	2

Senate Conference Committee
on
HB 25

Ex. 4

Roll Call Vote

DATE: 4-16-07

NAME	YES	NO
REP. OLSON	✓	
REP. LANGE	✓	
REP. THOMAS		✓
SEN. LASLOVICH	✓	
SEN. RYAN		✓
SEN. ESP	✓	
	4	2

2011 Montana Legislature

Additional Bill Links PDF version

HOUSE BILL NO. 271

INTRODUCED BY K. KERNS, HINKLE, HARRIS, VANCE, MILLER, HOWARD, RANDALL, INGRAHAM, WAGNER, WITTICH, YATES, KENNEDY, HALE, SKEES, FLYNN, HENDRICK, BLYTON, BLASDEL, TAYLOR, C. SMITH, REGIER, WARBURTON, G. BENNETT, HANSEN, LONEY, READ, MCGILLVRAY, KNOX, O'NEIL, GREEF, BRODEHL, MCNIVEN, SALOMON, K. PETERSON, SKATTUM, C. VINCENT

AN ACT REVISING THE LAW RELATED TO THE OFFENSE OF CARRYING A CONCEALED WEAPON; PROVIDING THAT THE LAW DOES NOT APPLY TO A PERSON WHO IS ELIGIBLE TO POSSESS A HANDGUN UNDER STATE OR FEDERAL LAW; AND AMENDING SECTION 45-8-317, MCA.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF MONTANA:

Section 1. Section 45-8-317, MCA, is amended to read:

"**45-8-317. Exceptions.** (1) Section 45-8-316 does not apply to:

(a) any peace officer of the state of Montana or of another state who has the power to make arrests;

(b) any officer of the United States government authorized to carry a concealed weapon;

(c) a person in actual service as a member of the national guard;

(d) a person summoned to the aid of any of the persons named in subsections (1)(a) through (1)(c);

(e) a civil officer or the officer's deputy engaged in the discharge of official business;

(f) a probation and parole officer authorized to carry a firearm under 46-23-1002;

(g) a person eligible to possess a handgun under state or federal law, a person issued a permit under 45-8-321, or ~~or~~ a person with a permit recognized under 45-8-329;

(h) an agent of the department of justice or a criminal investigator in a county attorney's office;

(i) a person who is outside the official boundaries of a city or town or the confines of a logging, lumbering,

mining, or railroad camp or who is lawfully engaged in hunting, fishing, trapping, camping, hiking, backpacking, farming, ranching, or other outdoor activity in which weapons are often carried for recreation or protection; or

(j) the carrying of arms on one's own premises or at one's home or place of business.

(2) With regard to a person issued a permit under 45-8-321, the provisions of 45-8-328 do not apply to this section."

- END -

Latest Version of HB 271 *(HB0271.ENR)*

Processed for the Web on May 2, 2011 (1:18pm)

New language in a bill appears underlined, deleted material appears stricken.

Sponsor names are handwritten on introduced bills, hence do not appear on the bill until it is reprinted.

See the status of this bill for the bill's primary sponsor.

Status of this Bill | 2011 Legislature | Leg. Branch Home

All versions of all bills (PDF format)

Authorized print version of this bill (PDF format)

[NEW SEARCH]

Prepared by Montana Legislative Services

(406) 444-3064

2007 Montana Legislature

About Bill -- Links

HOUSE BILL NO. 25
INTRODUCED BY A. OLSON, LASLOVICH
BY REQUEST OF THE ENERGY AND TELECOMMUNICATIONS INTERIM COMMITTEE

AN ACT GENERALLY REVISING THE ELECTRIC UTILITY INDUSTRY RESTRUCTURING AND CUSTOMER CHOICE LAWS; ELIMINATING AND CLARIFYING CERTAIN DEFINITIONS; DEFINING CERTAIN TERMS; CLARIFYING CUSTOMER OPTIONS REGARDING PURCHASING ELECTRICITY SUPPLY; CLARIFYING PUBLIC UTILITY AND COOPERATIVE UTILITY EXEMPTIONS; CLARIFYING ELECTRICITY SUPPLY AND PROCUREMENT REQUIREMENTS; CLARIFYING THE APPROVAL PROCESS FOR ELECTRICITY SUPPLY RESOURCES; REQUIRING THE COMMISSION TO ADDRESS CARBON OFFSETS IN THE APPROVAL PROCESS; CLARIFYING USE OF GENERATION ASSETS; AMENDING SECTIONS 15-72-103, 15-72-104, 35-19-102, 69-1-114, 69-8-101, 69-8-103, 69-8-201, 69-8-210, 69-8-311, 69-8-402, 69-8-403, 69-8-411, 69-8-419, 69-8-420, 69-8-421, 69-8-602, 69-8-603, AND 69-8-1004, MCA; AND REPEALING SECTIONS 69-8-102, 69-8-104, 69-8-202, 69-8-203, 69-8-204, 69-8-208, 69-8-209, 69-8-211, 69-8-301, 69-8-302, 69-8-303, 69-8-304, 69-8-308, 69-8-309, 69-8-310, 69-8-404, 69-8-408, 69-8-409, AND 69-8-410, MCA.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF MONTANA:

Section 1. Section 15-72-103, MCA, is amended to read:

"**15-72-103. Definitions.** As used in this part, unless the context requires otherwise, the following definitions apply:

(1) "Customer" or "purchaser" means a person who acquires for consideration electricity for use or consumption and not for resale.

(2) "Distribution services provider" means a person controlling or operating distribution facilities for distribution of electricity to the public. A distribution services provider includes a purchaser who takes electricity

directly from a transmission line or substation and a purchaser who generates electricity for the purchaser's own use but does not include electricity generated by the purchaser for noncommercial use or for agricultural use.

(3) "Person" means an individual, estate, trust, receiver, cooperative association, corporation, limited liability company, firm, partnership, joint venture, syndicate, or other entity, including any gas or electric utility owned or operated by a county, municipality, or other political subdivision of the state.

(4) "Transmission services provider" means a person or entity controlling or operating ~~transmission~~ facilities ~~as that term is defined in 69-8-103~~ used for the transmission of electricity."

Section 2. Section 15-72-104, MCA, is amended to read:

"15-72-104. Wholesale energy transaction tax -- rate of tax -- exemptions -- cost recovery. (1) (a) Except as provided in subsection (3), a wholesale energy transaction tax is imposed upon electricity transmitted within the state as provided in this section. The tax is imposed at a rate of 0.015 cent per kilowatt hour of electricity transmitted by a transmission services provider in the state.

(b) For electricity produced in the state for delivery outside ~~of~~ the state, the taxpayer is the person owning or operating the electrical generation facility producing the electricity. The transmission services provider shall collect the tax from the person based upon the kilowatt hours introduced onto transmission lines from the electrical generation facility. The amount of kilowatt hours subject to tax must be reduced by 5% to compensate for transmission line losses.

(c) For electricity produced in the state for delivery within the state, the taxpayer is the distribution services provider. The transmission services provider shall collect the tax based upon the amount of kilowatt hours of electricity delivered to the distribution services provider. The taxpayer may apply for a refund for overpayment of taxes pursuant to 15-72-116.

(d) For electricity produced outside the state for delivery inside the state, the taxpayer is the distribution services provider. The transmission services provider shall collect the tax based upon the amount of kilowatt hours of electricity delivered to the distribution services provider.

(e) For electricity delivered to a distribution services provider that is a rural electric cooperative for delivery to purchasers that have opted for customer choice under the provisions of Title 69, chapter 8, part 3, the taxpayer is the distribution services provider. The transmission services provider shall collect the tax based on the amount of kilowatt hours of electricity delivered to the distribution services provider that is attributable to customers that have opted for customer choice.

(f) For electricity delivered to a distribution services provider that prior to May 2, 1999, was owned by a public utility as defined in 69-3-101, the tax is imposed on the successor distribution services provider. The

transmission services provider shall collect the tax based upon the amount of kilowatt hours of electricity delivered to the distribution services provider.

(2) (a) If more than one transmission services provider transmits electricity, the last transmission services provider transmitting or delivering the electricity shall collect the tax.

(b) If the transmission services provider is an agency of the United States government, the distribution services provider receiving the electricity shall self-assess the tax subject to the provisions of this part.

(c) If an electrical generation facility located within the state produces electricity for sale inside and outside the state, sales within the state are considered to have come from electricity produced within the state for purposes of the tax imposed by this section.

(3) (a) Electricity transmitted through the state that is not produced or delivered in the state is exempt from the tax imposed by this section.

(b) Electricity produced in the state by an agency of the United States government or electricity produced from an electric energy generation facility, as defined in 90-5-101(3), constructed after May 1, 2001, that is within the exterior boundaries of a Montana Indian reservation for delivery outside ~~of~~ the state is exempt from the tax imposed by this section.

(c) Electricity produced by wind turbines erected on state land for which annual lease payments are made to the permanent school trust fund is exempt from the tax imposed by this section.

(d) Electricity delivered to a distribution services provider that is a municipal utility described in ~~69-8-103(5)(b)~~ 69-8-103(4)(b) or a rural electric cooperative organized under the provisions of Title 35, chapter 18, is exempt from the tax imposed by this section.

(e) Electricity delivered to a purchaser that receives its power directly from a transmission or distribution facility owned by an entity of the United States government on or before May 2, 1997, or electricity that is transmitted exclusively on transmission or distribution facilities owned by an entity of the United States government on or before May 2, 1997, is exempt from the tax imposed by this section.

(4) A distribution services provider is allowed to recover the tax imposed by this section and the administrative costs to comply with this part in its rates."

Section 3. Section 35-19-102, MCA, is amended to read:

"35-19-102. Definitions. As used in this chapter, unless the context requires otherwise, the following definitions apply:

(1) "Distribution utility" means ~~the electricity distribution portion of a public utility as defined in 69-8-103~~ a utility owning distribution facilities for distribution of electricity to the public.

(2) "Residential customer" means a residential customer of a distribution utility.

(3) "Small commercial customer" means, for a distribution utility, individual accounts of a commercial customer with an average monthly demand in the previous calendar year of less than 100 kilowatts or a new commercial customer with an estimated average monthly demand of less than 100 kilowatts.

(4) "Small customer" means a residential customer or small commercial customer of a distribution utility."

Section 4. Section 69-1-114, MCA, is amended to read:

"69-1-114. Fees. (1) Each fee charged by the commission must be reasonable.

(2) Except for a fee assessed pursuant to 69-3-204(2), ~~69-8-421(7)~~ 69-8-421(10), or 69-12-423(2), a fee set by the commission may not exceed $500.

(3) All fees collected by the department under ~~69-8-421(7)~~ 69-8-421(10) must be deposited in an account in the special revenue fund. Funds in this account must be used as provided in ~~69-8-421(7)~~ 69-8-421(10)."

Section 5. Section 69-8-101, MCA, is amended to read:

"69-8-101. Short title. This chapter may be cited as the "Electric Utility Industry ~~Restructuring and Customer Choice~~ Generation Reintegration Act"."

Section 6. Section 69-8-103, MCA, is amended to read:

"69-8-103. Definitions. As used in this chapter, unless the context requires otherwise, the following definitions apply:

~~(1) "Aggregator" or "market aggregator" means an entity, licensed by the commission, that aggregates retail customers, purchases electrical energy, and takes title to electrical energy as an intermediary for sale to retail customers.~~

~~(2)~~(1) "Assignee" means any entity, including a corporation, partnership, board, trust, or financing vehicle, to which a utility assigns, sells, or transfers, other than as security, all or a portion of the utility's interest in or right to transition property. The term also includes an entity, corporation, public authority, partnership, trust, or financing vehicle to which an assignee assigns, sells, or transfers, other than as security, the assignee's interest in or right to transition property.

~~(3)~~(2) "Board" means the board of investments created by 2-15-1808.

~~(4) "Broker" or "marketer" means an entity, licensed by the commission, that acts as an agent or intermediary in the sale and purchase of electrical energy but that does not take title to electrical energy.~~

(3) "Carbon offset provider" means a qualified third-party entity that arranges for projects or actions that

either reduce carbon dioxide emissions or that increase the absorption of carbon dioxide.

~~(5)~~(4) "Cooperative utility" means:

(a) a utility qualifying as an electric cooperative pursuant to Title 35, chapter 18; or

(b) an existing municipal electric utility as of May 2, 1997.

~~(6) "Customer" or "consumer" means a retail electric customer or consumer. The university of Montana, pursuant to 20-25-201(1), and Montana state university, pursuant to 20-25-201(2), are each considered a single retail electric customer or consumer with a single individual load.~~

(5) "Cost-effective carbon offsets" means any combination of certified actions that are taken to reduce carbon dioxide emissions or that increase the absorption of carbon dioxide, which collectively do not increase the cost of electricity produced annually on a per-megawatt-hour basis by more than 2.5%, including:

(a) actions undertaken by the applicant that reduce carbon dioxide emissions or that increase the absorption of carbon dioxide from a facility or equipment used to generate electricity; or

(b) actions by a carbon offset provider on behalf of the applicant.

~~(7)~~(6) "Customer-generator" means a user of a net metering system.

~~(8) "Default supplier" means a distribution services provider of a utility that has restructured in accordance with this chapter.~~

~~(9) "Default supply service" means the provision of electricity supply by a default supplier.~~

~~(10) "Distribution facilities" means those facilities by and through which electricity is received from a transmission services provider and distributed to the customer and that are controlled or operated by a distribution services provider.~~

~~(11) "Distribution services provider" means a utility owning distribution facilities for distribution of electricity to the public.~~

~~(12) "Electricity supplier" means any person, including aggregators, market aggregators, brokers, and marketers, offering to sell electricity to retail customers in the state of Montana.~~

(7) "Distribution facilities" means those facilities by and through which electricity is received from transmission facilities and distributed to a retail customer and that are controlled or operated by a utility.

~~(13)~~(8) "Electricity supply costs" means the actual costs ~~of~~ incurred in providing ~~default~~ electricity supply service through power purchase agreements, demand-side management, and energy efficiency programs, including but not limited to:

(a) capacity costs;

(b) energy costs;

(c) fuel costs;

(d) ancillary service costs;

~~(e) demand-side management and energy efficiency costs;~~

~~(f)~~(e) transmission costs, including congestion and losses;

~~(g) billing costs;~~

~~(h)~~(f) planning and administrative costs; and ~~and~~

~~(i)~~(g) any other costs directly related to the purchase of electricity~~,~~ and the management ~~of default electricity supply costs,~~ and provision of ~~default supply and related services.~~ power purchase agreements.

(9) "Electricity supply resource" means:

(a) contracts for electric capacity and generation;

(b) plants owned or leased by a utility or equipment used to generate electricity;

(c) customer load management and energy conservation programs; or

(d) other means of providing adequate, reliable service to customers, as determined by the commission.

(10) "Electricity supply service" means the provision of electricity supply and related services through power purchase agreements, the acquisition and operation of electrical generation facilities, demand-side management, and energy efficiency programs.

~~(14)~~(11) "Financing order" means an order of the commission adopted in accordance with 69-8-503 that authorizes the imposition and collection of fixed transition amounts and the issuance of transition bonds.

~~(15)~~(12) (a) "Fixed transition amounts" means those nonbypassable rates or charges, including but not limited to:

(i) distribution;

(ii) connection;

(iii) disconnection; and

(iv) termination rates and charges that are authorized by the commission in a financing order to permit recovery of transition costs and the costs of recovering, reimbursing, financing, or refinancing the transition costs and of acquiring transition property through a plan approved by the commission in the financing order, including the costs of issuing, servicing, and retiring transition bonds.

(b) If requested by the utility in the utility's application for a financing order, fixed transition amounts must include nonbypassable rates or charges to recover federal and state taxes in which the transition cost recovery period is modified by the transactions approved in the financing order.

~~(16) "Functionally separate" means a utility's separation of the utility's electricity supply, transmission, distribution, and unregulated retail energy services assets and operations.~~

(13) "Generation assets cost of service" means a return on invested capital and all costs associated with the

acquisition, construction, administration, operation, and maintenance of a plant or equipment owned or leased by a public utility and used for the production of electricity.

~~(17)~~(14) "Interested person" means a retail electricity customer, the consumer counsel established in 5-15-201, the commission, or a utility.

~~(18)~~(15) "Large customer" means, for universal system benefits programs purposes, a customer with an individual load greater than a monthly average of 1,000 kilowatt demand in the previous calendar year for that individual load.

~~(19)~~(16) "Local governing body" means a local board of trustees of a rural electric cooperative.

~~(20)~~(17) "Low-income customer" means those energy consumer households and families with incomes at or below industry-recognized levels that qualify those consumers for low-income energy-related assistance.

~~(21)~~(18) "Net metering" means measuring the difference between the electricity distributed to and the electricity generated by a customer-generator that is fed back to the distribution system during the applicable billing period.

~~(22)~~(19) "Net metering system" means a facility for the production of electrical energy that:

(a) uses as its fuel solar, wind, or hydropower;

(b) has a generating capacity of not more than 50 kilowatts;

(c) is located on the customer-generator's premises;

(d) operates in parallel with the ~~distribution services provider's~~ utility's distribution facilities; and

(e) is intended primarily to offset part or all of the customer-generator's requirements for electricity.

~~(23)~~(20) "Nonbypassable rates or charges" means rates or charges that are approved by the commission and imposed on a customer to pay the customer's share of transition costs or universal system benefits programs costs even if the customer has physically bypassed either the utility's transmission or distribution facilities.

~~(24) "Pilot program" means an experimental program using a select set of small customers to assess the potential for developing and offering customer choice of electricity supply to small customers in the future.~~

~~(25)~~(21) "Public utility" ~~means any electric utility~~ has the meaning of a public utility regulated by the commission pursuant to Title 69, chapter 3~~, on May 2, 1997, including the public utility's successors or assignees~~, on May 2, 1997, including the public utility's successors or assignees.

~~(26)~~(22) "Qualifying load" means, for payments and credits associated with universal system benefits programs, all nonresidential demand-metered accounts of a large customer within the utility's service territory in which the customer qualifies as a large customer.

~~(27) "Small customer" means a residential customer or a commercial customer who has an individual~~

~~account with an average monthly demand in the previous calendar year of less than 50 kilowatts or a new residential or commercial customer with an estimated average monthly demand of less than 50 kilowatts of a public utility that has restructured pursuant to Title 35, chapter 19, or this chapter.~~

(23) "Retail customer" means a customer that purchases electricity for residential, commercial, or industrial end-use purposes and does not resell electricity to others.

~~(28)~~(24) "Transition bondholder" means a holder of transition bonds, including trustees, collateral agents, and other entities acting for the benefit of that bondholder.

~~(29)~~(25) "Transition bonds" means any bond, debenture, note, interim certificate, collateral, trust certificate, or other evidence of indebtedness or ownership issued by the board or other transition bonds issuer that is secured by or payable from fixed transition amounts or transition property. Proceeds from transition bonds must be used to recover, reimburse, finance, or refinance transition costs and to acquire transition property.

~~(30)~~(26) "Transition charge" means a nonbypassable rate or charge to be imposed on a customer to pay the customer's share of transition costs.

~~(31)~~(27) "Transition cost recovery period" means the period beginning on July 1, 1998, and ending when a utility customer does not have any liability for payment of transition costs.

~~(32)~~(28) "Transition costs" means:

(a) a public utility's net verifiable generation-related and electricity supply costs, including costs of capital, that become unrecoverable as a result of the implementation of ~~this chapter or of~~ federal law requiring retail open access or customer choice or of this chapter;

(b) those costs that include but are not limited to:

(i) regulatory assets and deferred charges that exist because of current regulatory practices and can be accounted for up to the effective date of the commission's final order regarding a public utility's transition plan and conservation investments made prior to universal system benefits charge implementation;

(ii) nonutility and utility power purchase contracts executed before May 2, 1997, including qualifying facility contracts;

(iii) existing generation investments and supply commitments or other obligations incurred before May 2, 1997, and costs arising from these investments and commitments;

(iv) the costs associated with renegotiation or buyout of the existing nonutility and utility power purchase contracts, including qualifying facilities and all costs, expenses, and reasonable fees related to issuing transition bonds; and

(v) the costs of refinancing and retiring of debt or equity capital of the public utility and associated federal and state tax liabilities or other utility costs for which the use of transition bonds would benefit customers.

~~(33) "Transition period" means the period ending July 1, 2027.~~

~~(34)~~(29) "Transition property" means the property right created by a financing order, including without limitation the right, title, and interest of a utility, assignee, or other issuer of transition bonds to all revenue, collections, claims, payments, money, or proceeds of or arising from or constituting fixed transition amounts that are the subject of a financing order, including those nonbypassable rates and other charges and fixed transition amounts that are authorized by the commission in the financing order to recover transition costs and the costs of recovering, reimbursing, financing, or refinancing the transition costs and acquiring transition property, including the costs of issuing, servicing, and retiring transition bonds. Any right that a utility has in the transition property before the utility's sale or transfer or any other right created under this section or created in the financing order and assignable under this chapter or assignable pursuant to a financing order is only a contract right.

~~(35) "Transmission facilities" means those facilities that are used to provide transmission services as determined by the federal energy regulatory commission and the commission.~~

~~(36) "Transmission services provider" means an entity controlling or operating transmission facilities.~~

(30) "Transmission facilities" means those facilities that are used to provide transmission services as determined by the federal energy regulatory commission and the commission and that are controlled or operated by a utility.

~~(37)~~(31) "Universal system benefits charge" means a nonbypassable rate or charge to be imposed on a customer to pay the customer's share of universal system benefits programs costs.

~~(38)~~(32) "Universal system benefits programs" means public purpose programs for:

(a) cost-effective local energy conservation;

(b) low-income customer weatherization;

(c) renewable resource projects and applications, including those that capture unique social and energy system benefits or that provide transmission and distribution system benefits;

(d) research and development programs related to energy conservation and renewables;

(e) market transformation designed to encourage competitive markets for public purpose programs; and

(f) low-income energy assistance.

~~(39)~~(33) "Utility" means any public utility or cooperative utility."

Section 7. Section 69-8-201, MCA, is amended to read:

"69-8-201. Public utility -- ~~transition to customer choice --~~ customer electricity supply service options and requirements -- ~~waiver~~ exemption. ~~(1) Before July 1, 2027, all public utility customers of a public utility that has restructured in accordance with this chapter must have the opportunity to choose an electricity supplier~~

~~other than the default supplier.~~

~~(2) (a) A small customer of a public utility that has restructured in accordance with this chapter:~~

~~(i) must receive default supply services from the default supplier as provided in this chapter; and~~

~~(ii) may purchase electricity supply services through a commission-approved small customer electricity supply program as provided in this section.~~

~~(b) A small customer receiving electricity from a licensed supplier prior to July 1, 2003, may continue to receive electricity supply from a supplier other than the default supplier.~~

~~(c) Customers that represent separately metered services with an estimated average monthly demand of less than 50 kilowatts related to the same individual customer referred to in subsection (3) or (4) may be combined with the respective eligible customer load or loads.~~

~~(3) (a) Subject to subsection (3)(b), a customer of a public utility that has restructured in accordance with this chapter and that has an individual load with an average monthly demand of less than 5,000 kilowatts but greater than or equal to 50 kilowatts may choose an electricity supplier.~~

~~(b) The total average monthly billing demand for all customers that choose an electricity supplier pursuant to subsection (3)(a) in each calendar year may not exceed 20,000 kilowatts.~~

~~(c) A customer referred to in subsection (3)(a) receiving electricity from a licensed supplier prior to July 1, 2003, may continue to receive electricity supply from a supplier other than the default supplier.~~

~~(4)~~(1) (a) Except as provided in subsections ~~(4)(b)~~ (1)(b) ~~through (4)(c)~~ and (1)(c), a retail customer ~~of a utility that has restructured in accordance with this chapter and~~ that has an individual load with an average monthly demand of greater than or equal to 5,000 kilowatts ~~shall purchase its entire electricity supply from the competitive marketplace~~ and that is not purchasing electricity supply service from a public utility on [the effective date of this act] may not purchase electricity supply service from a public utility.

~~(b) A customer referred to in subsection (4)(a) that is receiving its electricity supply from the competitive marketplace may make a one-time election to enter into a permanent power supply contract with the default supplier for service on or after July 1, 2004. These contracts must include the applicable provisions established by the commission pursuant to subsection (5). This election must be submitted to the commission in writing no later than December 31, 2003.~~

~~(c)~~(b) A ~~new~~ retail customer ~~with an estimated average monthly demand of greater than or equal to 5,000 kilowatts may enter into a power supply contract with the default supplier in order to receive default supply service~~ referred to in subsection (1)(a) may request electricity supply service from the public utility, and the public utility must provide electricity supply service if the retail customer demonstrates that the provision of electricity supply service to the retail customer will not adversely impact the public utility's other customers over

the long term as determined by the commission. ~~The new customer's election of an electricity supplier must be submitted in writing to the commission at least 90 days before delivery of electricity. These contracts must include the applicable provisions established by the commission pursuant to subsection (5).~~

~~(d) A customer referred to in subsection (4)(a) that was receiving electricity from the default supplier on July 1, 2003, may continue to receive electricity from the default supplier.~~

(c) If a public utility provides electricity supply service to a retail customer as provided in subsection (1)(b), that service is regulated by the commission and the customer may not, at a later date, purchase electricity supply service from another provider of electricity supply service.

~~(e) A customer referred to in subsection (4)(a) that is a public agency, as defined in 18-1-101, may enter into a power supply contract with the default supplier for default supply service for all or part of the public agency's load. These contracts must include the applicable provisions established by the commission pursuant to subsection (5).~~

~~(5) The commission shall adopt rules and establish rates and fees to enable customers to have reasonable opportunities to choose an electricity supplier or to receive default supply service in accordance with subsections (2) through (4), while providing protection for small customers from higher or more unstable default supply service rates than would otherwise result if these choices were not offered.~~

~~(6) An electricity supplier licensed by the commission to offer electricity supply service to small customers may petition the commission for the opportunity to provide electricity to small customers. The total average monthly demand for all customers referred to in subsection (2)(a) in each calendar year that receive service from an electricity supplier that is not the default supplier may not exceed 10,000 kilowatts. The commission shall ensure that electricity supply service provided pursuant to this subsection is consistent with the requirements in subsection (5) and the provision of default supply service pursuant to this chapter.~~

~~(7) Based on an analysis of the sources of costs of providing default supply service, the commission may:~~

~~(a) establish different categories of default supply service customers to assist with the implementation of this section;~~

~~(b) allocate default supply costs; and~~

~~(c) develop default supply rates.~~

~~(8) (a) Except as provided in subsection (8)(b), a customer receiving default supply service may not resell the electricity.~~

~~(b) A default supplier may implement demand reduction programs that reward customers for reducing demand under terms established by the commission.~~

(2) (a) A retail customer that has an individual load with an average monthly demand of less than 5,000

kilowatts that is not purchasing electricity from a public utility on [the effective date of this act] may continue to purchase electricity from an electricity supplier. The retail customer may subsequently purchase electricity from a public utility subject to commission rule or order, but the customer may not, at a later date, choose to purchase electricity from another source.

(b) A retail customer that has an individual load with an average monthly demand of less than 5,000 kilowatts and that is currently purchasing electricity from a public utility may not choose to purchase electricity from another source after [the effective date of this act].

(3) Nothing in this section affects a retail customer's rights and obligations with respect to net metering, cogeneration, self-generation, or ancillary sales of electricity related to deviations from scheduled energy deliveries from nonutility suppliers, as may be provided for in law, commission rule or order, or a tariff approved by the public service commission or the federal energy regulatory commission.

~~(9)~~(4) (a) Except as provided in 69-5-101, 69-5-102, 69-5-104 through 69-5-112, ~~and~~ 69-8-402, and subsection (4)(b) of this section, a public utility currently doing business in Montana as part of a single integrated multistate operation, no portion of which lies within the basin of the Columbia River, ~~may defer compliance with this chapter until a time that the public utility can reasonably implement customer choice in the state of the public utility's primary service territory~~ is exempt from the requirements of this chapter.

(b) To the extent that a public utility described in subsection ~~(9)(a)~~ (4)(a) becomes the successor in interest of another public utility that has restructured in accordance with this chapter before [the effective date of this act], ~~it shall assume responsibility only for the applicable transition plan of~~ it is subject to the requirements of this chapter with respect to the service area of the acquired public utility.

~~(10) Upon a request from a public utility with fewer than 50 customers, the commission shall waive compliance with the requirements of 69-8-104, 69-8-202 through 69-8-204, 69-8-208 through 69-8-211, 69-8-402, and this section.~~"

Section 8. Section 69-8-210, MCA, is amended to read:

"**69-8-210. Public utilities -- electricity supply -- environmentally preferred resources.** ~~(1) A public utility's distribution services provider shall provide default supply service.~~

~~(2)~~(1) The commission shall establish an electricity cost recovery mechanism that allows a ~~default supplier~~ public utility to fully recover prudently incurred electricity supply costs, subject to the provisions of 69-8-419 ~~and~~, 69-8-420, and commission rules. The commission may include other utility costs and expenses in the cost recovery mechanism if it determines that including additional costs and expenses is reasonable and in the public interest. The cost recovery mechanism must provide for prospective rate adjustments for cost differences resulting from cost changes, load changes, and the time value of money on the differences.

~~(3) The commission may direct a default supplier to offer its customers multiple default supply service options if the commission determines that those options are in the public interest and are consistent with the provisions of 69-8-104 and 69-8-201.~~

~~(4)~~(2) Notwithstanding any service options that the commission may require ~~pursuant to subsection (3), a default supplier~~, a public utility shall offer its customers the option of purchasing a product composed of or supporting power from certified environmentally preferred resources that include but are not limited to wind, solar, geothermal, and biomass, subject to review and approval by the commission. The commission shall ensure that these resources have been certified as meeting industry-accepted standards.

~~(5) (a) Subject to subsection (5)(b), the commission shall, in reviewing the procurement of electricity supply by the default supplier, take into account the statewide economic benefits that are associated with the electricity supply procurement for the default supply stakeholders. The default supply stakeholders include the default supplier, customers of the default supplier, and the public.~~

~~(b) The consideration of economic benefits is secondary to the consideration of the costs and benefits to the consumer and other criteria established by law.~~

~~(6) If a public utility intends to be an electricity supplier through an unregulated division, then the public utility must be licensed as an electricity supplier pursuant to 69-8-404.~~"

Section 9. Section 69-8-311, MCA, is amended to read:

"**69-8-311. Cooperative utility -- electricity supply service -- exemption.** (1) A local governing body shall establish the price for electricity supply service offered by a cooperative utility.

~~(1) Within 1 year after May 2, 1997, a cooperative utility may file a notice with the commission that the cooperative utility does not intend to open the cooperative utility's distribution facilities to electricity suppliers and does not intend to adopt a transition plan.~~

(2) Except as otherwise provided in the universal system benefits program pursuant to 69-8-402, a cooperative utility ~~filing notice under this section~~ is exempt from the provisions and requirements of this chapter.

~~(2) A cooperative utility filing a notice under this section:~~

~~(a) may elect later to adopt a transition plan in accordance with this chapter; and~~

~~(b) may not use a public utility's distribution facilities unless preexisting contracts exist.~~"

Section 10. Section 69-8-402, MCA, is amended to read:

"**69-8-402. Universal system benefits programs.** (1) Universal system benefits programs are established for the state of Montana to ensure continued funding of and new expenditures for energy conservation,

renewable resource projects and applications, and low-income energy assistance.

(2) Beginning January 1, 1999, 2.4% of each utility's annual retail sales revenue in Montana for the calendar year ending December 31, 1995, is established as the initial funding level for universal system benefits programs. To collect this amount of funds on an annualized basis in 1999, the commission shall establish rates for utilities subject to its jurisdiction and the governing boards of cooperatives shall establish rates for the cooperatives. These universal system benefits charge rates must remain in effect through December 31, 2009.

(a) The recovery of all universal system benefits programs costs imposed pursuant to this section is authorized through the imposition of a universal system benefits charge assessed at the meter for each local utility system customer as provided in this section.

(b) A utility must receive credit toward annual funding requirements for the utility's internal programs or activities that qualify as universal system benefits programs, including those amortized or nonamortized portions of expenditures for the purchase of power that are for the acquisition or support of renewable energy, conservation-related activities, or low-income energy assistance, and for large customers' programs or activities as provided in subsection (7). The department of revenue shall review claimed credits of the utilities and large customers pursuant to 69-8-414.

(c) A ~~utility's distribution services provider~~ utility at which the sale of power for final end use occurs is the utility that receives credit for the universal system benefits programs expenditure.

(d) A customer's ~~distribution services provider~~ utility shall collect universal system benefits funds less any allowable credits.

(e) For a utility to receive credit for low-income-related expenditures, the activity must have taken place in Montana.

(f) If a utility's or a large customer's credit for internal activities does not satisfy the annual funding provisions of subsection (2), then the utility shall make a payment to the universal system benefits fund established in 69-8-412 for any difference.

(3) Cooperative utilities may collectively pool their statewide credits to satisfy their annual funding requirements for universal system benefits programs and low-income energy assistance.

(4) A utility's transition plan must describe how the utility proposes to provide for universal system benefits programs, including the methodologies, such as cost-effectiveness and need determination, used to measure the utility's level of contribution to each program.

(5) A utility's minimum annual funding requirement for low-income energy and weatherization assistance is established at 17% of the utility's annual universal system benefits funding level and is inclusive within the overall universal system benefits funding level.

(a) A utility must receive credit toward the utility's low-income energy assistance annual funding requirement for the utility's internal low-income energy assistance programs or activities.

(b) If a utility's credit for internal activities does not satisfy its annual funding requirement, then the utility shall make a payment for any difference to the universal low-income energy assistance fund established in 69-8-412.

(6) An individual customer may not bear a disproportionate share of the local utility's funding requirements, and a sliding scale must be implemented to provide a more equitable distribution of program costs.

(7) (a) A large customer:

(i) shall pay a universal system benefits programs charge with respect to the large customer's qualifying load equal to the lesser of:

(A) $500,000, less the large customer credits provided for in this subsection (7); or

(B) the product of 0.9 mills per kilowatt hour multiplied by the large customer's total kilowatt hour purchases, less large customer credits with respect to that qualifying load provided for in this subsection (7);

(ii) must receive credit toward that large customer's universal system benefits charge for internal expenditures and activities that qualify as a universal system benefits programs expenditure, and these internal expenditures must include but not be limited to:

(A) expenditures that result in a reduction in the consumption of electrical energy in the large customer's facility; and

(B) those amortized or nonamortized portions of expenditures for the purchase of power at retail or wholesale that are for the acquisition or support of renewable energy or conservation-related activities.

(b) Large customers making these expenditures must receive a credit against the large customer's universal system benefits charge, except that any of those amounts expended in a calendar year that exceed that large customer's universal system benefits charge for the calendar year must be used as a credit against those charges in future years until the total amount of those expenditures has been credited against that large customer's universal system benefits charges.

(8) A public utility shall prepare and submit an annual summary report of the public utility's activities relating to all universal system benefits programs to the commission, the department of revenue, and the energy and telecommunications interim committee provided for in 5-5-230. A cooperative utility shall prepare and submit annual summary reports of activities to the cooperative utility's respective local governing body, the statewide cooperative utility office, and the energy and telecommunications interim committee. The statewide cooperative utility office shall prepare and submit an annual summary report of the activities of individual cooperative utilities, including a summary of the pooling of statewide credits, as provided in subsection (3), to the department of revenue and the energy and telecommunications interim committee. The annual report of a public utility or of the

statewide cooperative utility office must include but is not limited to:

(a) the types of internal utility and customer programs being used to satisfy the provisions of this chapter;

(b) the level of funding for those programs relative to the annual funding requirements prescribed in subsection (2); and

(c) any payments made to the statewide funds in the event that internal funding was below the prescribed annual funding requirements.

(9) A utility or large customer filing for a credit shall develop and maintain appropriate documentation to support the utility's or the large customer's claim for the credit.

(10) (a) A large customer claiming credits for a calendar year shall submit an annual summary report of its universal system benefits programs activities and expenditures to the department of revenue and to the large customer's utility. The annual report of a large customer must identify each qualifying project or expenditure for which it has claimed a credit and the amount of the credit. Prior approval by the department of revenue or the utility is not required, except as provided in subsection (10)(b).

(b) If a large customer claims a credit that the department of revenue disallows in whole or in part, the large customer is financially responsible for the disallowance. A large customer and the large customer's utility may mutually agree that credits claimed by the large customer be first approved by the utility. If the utility approves the large customer credit, the utility may be financially responsible for any subsequent disallowance."

Section 11. Section 69-8-403, MCA, is amended to read:

"**69-8-403. Commission ~~authority --~~ rulemaking authority.** ~~(1) Beginning on the effective date of a commission order regarding a public utility's transition plan, the commission shall regulate the public utility's retail transmission, distribution, and default supply services within the state of Montana, as provided in this chapter.~~

~~(2) The commission shall license electricity suppliers and enforce licensing provisions pursuant to 69-8-404.~~

~~(3) The commission shall promulgate rules that identify the licensees and ensure that the offered electricity supply is provided as offered and is adequate in terms of quality, safety, and reliability.~~

~~(4) The commission shall establish just and reasonable rates through established ratemaking principles for public utility default supply, distribution, and transmission services and shall regulate these services. The commission may approve rates and charges for those services based on alternative forms of ratemaking such as performance-based ratemaking, on a demonstration by the public utility that the alternative method complies with this chapter, and on the public utility's transition plan.~~

~~(5) The commission shall certify that a cooperative utility has adopted a transition plan that complies with this~~

~~chapter. A cooperative utility's transition plan is considered certified 60 days after the cooperative utility files for certification.~~

~~(6) The commission shall promulgate rules that protect consumers, distribution services providers, and electricity suppliers from anticompetitive and abusive practices.~~

~~(7) (a) After July 1, 2010, the commission shall continuously monitor whether or not workable competition has developed for small customers.~~

~~(b) If the commission determines that workable competition has developed for small customers after July 1, 2010, the commission shall provide a report to the legislature that includes recommendations for legislative implementation of customer choice for small customers.~~

~~(8)~~ In addition to promulgating rules expressly provided for in this chapter, the commission may promulgate any other rules necessary to carry out the provision of this chapter.

~~(9) This chapter does not give the commission the authority to:~~

~~(a) regulate cooperative utilities in any manner other than reviewing certification filings for compliance with this chapter; or~~

~~(b) compel any change to a cooperative utility's certification filing made pursuant to this chapter.~~"

Section 12. Section 69-8-411, MCA, is amended to read:

"**69-8-411. Nondiscriminatory access ~~-- reciprocity~~.** ~~Except as provided in 69-8-311, all electricity suppliers must be afforded open, fair, and nondiscriminatory access to customers and a comparable opportunity to compete. A distribution services provider or the distribution services provider's affiliates may not use another distribution services provider's facilities in the state of Montana to sell electricity to customers in the state of Montana unless the first distribution services provider or the distribution services provider's affiliates offer comparable and nondiscriminatory access to the distribution services provider's distribution facilities within the state of Montana.~~ (1) Nonutility generators and electricity suppliers must have open, fair, and nondiscriminatory access to a public utility's transmission and distribution facilities according to federal energy regulatory commission rules and regulations for purposes of serving those customers identified in 69-8-201(1) and (2).

(2) Public utilities shall grant the retail customers identified in 69-8-201(1) and (2) and their electricity suppliers access to transmission and distribution facilities at rates and under terms and conditions comparable to the public utility's own access to those facilities or access by the public utility's affiliates.

(3) Public utilities shall file tariffs for transmission and distribution services regulated by the federal energy regulatory commission and the commission implementing subsections (1) and (2)."

Section 13. Section 69-8-419, MCA, is amended to read:

"69-8-419. ~~Default~~ Electricity supply resource planning and procurement -- duties of ~~default supplier~~ public utility -- objectives -- commission rules. (1) The ~~default supplier~~ public utility shall:

(a) plan for future ~~default~~ electricity supply resource needs;

(b) manage a portfolio of ~~default~~ electricity supply resources; and

(c) procure new ~~default~~ electricity supply resources when needed.

(2) The ~~default supplier~~ public utility shall pursue the following objectives in fulfilling its duties pursuant to subsection (1):

(a) provide adequate and reliable ~~default supply services~~ electricity supply service at the lowest long-term total cost;

(b) conduct an efficient ~~default~~ electricity supply resource planning and procurement process that evaluates the full range of cost-effective electricity supply and demand-side management options;

(c) identify and cost-effectively manage and mitigate risks related to its obligation to provide ~~default~~ electricity supply service;

(d) use open, fair, and competitive procurement processes whenever possible; and

(e) provide ~~default supply services~~ electricity supply service and related services at just and reasonable rates.

(3) ~~By December 31, 2003, the~~ By March 31, 2008, the commission shall adopt rules that guide the ~~default~~ electricity supply resource planning and procurement processes used by the ~~default supplier~~ public utility and facilitate the achievement of the objectives in subsection (2) by the ~~default supplier~~ public utility. The rules must establish:

(a) goals, objectives, and guidelines that are consistent with the objectives in subsection (2) for:

(i) planning for future ~~default~~ electricity supply resource needs;

(ii) managing the portfolio of ~~default~~ electricity supply resources; and

(iii) procuring new ~~default~~ electricity supply resources;

(b) standards for the evaluation by the commission of the reasonableness of a power supply purchase agreement proposed by the ~~default supplier~~ public utility; and

(c) minimum filing requirements for an application by the ~~default supplier~~ public utility for ~~advanced approval of a proposed power supply purchase agreement~~ approval of an electricity supply resource."

Section 14. Section 69-8-420, MCA, is amended to read:

"69-8-420. ~~Default~~ Electricity supply resource procurement plans -- comment on plans. (1) The ~~default~~

~~supplier~~ public utility shall develop ~~default~~ electricity supply resource procurement plans. The plans must be submitted to the commission at intervals determined in rules adopted by the commission ~~pursuant to 69-8-419~~.

(2) ~~A default~~ An electricity supply resource procurement plan must demonstrate the ~~default supplier's~~ public utility's achievement of the objectives provided in 69-8-419 and compliance with ~~the rules adopted pursuant to 69-8-419~~ commission rules.

(3) The commission shall:

(a) review the ~~default~~ electricity supply resource procurement plan;

(b) provide an opportunity to the public to comment on the plan; and

(c) issue written comments that identify:

(i) any concerns of the commission regarding the ~~default supplier's~~ public utility's compliance with ~~the rules adopted pursuant to 69-8-419; and~~ commission rules; and

(ii) ways to remedy any concerns."

Section 15. Section 69-8-421, MCA, is amended to read:

"**69-8-421. ~~Default supply filings -- commission processing and approval~~ Approval of electricity supply resources.** (1) A ~~default supplier~~ public utility that removed its generation assets from its rate base pursuant to this chapter prior to [the effective date of this act] may apply to the commission for approval of an electricity supply resource that is not yet procured. ~~advanced approval of a power supply purchase agreement that is:~~

~~(a) not executed; or~~

~~(b) executed with a provision that allows termination of the agreement if the commission does not find the agreement reasonable.~~

~~(2) (a) The commission shall issue an order on the default supplier's application for advanced approval of a power supply purchase agreement in a timely manner as provided in this subsection (2).~~

~~(b) In establishing an administrative procedure for reviewing an application for advanced approval, the commission shall consider any financing and market constraints and the due process rights of affected persons.~~

~~(c)~~(2) Within 45 days of the ~~default supplier's~~ public utility's submission of an application for ~~advanced approval~~ approval, the commission shall determine whether or not the application is adequate and in compliance with the commission's minimum filing requirements. If the commission determines that the application is inadequate, it shall explain ~~how the filing fails to comply with the objectives in 69-8-419 and the rules adopted pursuant to 69-8-419.~~ the deficiencies.

~~(d)~~(3) The commission shall issue an order within 180 days of receipt of an adequate application for

approval of a power purchase agreement from an existing generating resource unless it determines that extraordinary circumstances require additional time.

(4) (a) Except as provided in subsections (4)(b) through (4)(d), the commission shall issue an order within 270 days of receipt of an adequate application for approval of a lease, an acquisition of an equity interest in a new or existing plant or equipment used to generate electricity, or a power purchase agreement for which approval would result in construction of a new electric generating resource. The commission may extend the time limit up to an additional 90 days if it determines that extraordinary circumstances require it.

(b) If an air quality permit pursuant to Title 75, chapter 2, is required for a new electrical generation resource or a modification to an existing resource, the commission shall hold the public hearing on the application for approval at least 30 days after the issuance of the final air quality permit.

(c) If a final air quality permit is not issued within the time limit pursuant to subsection (4)(a), the commission shall extend the time limit in order to comply with subsection (4)(b).

(d) The commission may extend the time limit for issuing an order for an additional 60 days following the hearing pursuant to subsection (4)(b).

~~(c)~~(5) To facilitate timely consideration of an application, the commission may initiate proceedings to evaluate planning and procurement activities related to a potential resource procurement prior to the ~~default supplier's~~ public utility's submission of an application for ~~approval~~ approval.

~~(3)~~(6) (a) The commission may approve or deny, in whole or in part, an application for ~~advanced approval of a power supply purchase agreement~~ approval of an electricity supply resource.

(b) The commission may consider all relevant information known up to the time that the administrative record in the proceeding is closed in the evaluation of an application for ~~advanced approval of a power supply purchase agreement~~ approval.

(c) A commission order granting ~~advanced approval of a power supply purchase agreement~~ approval of an application must include the following findings:

(i) ~~advanced approval of all or part of the agreement~~ approval, in whole or in part, is in the public interest; and

~~(ii) the agreement resulted from a reasonable effort by the default supplier to comply with the objectives in 69-8-419 and the rules adopted pursuant to 69-8-419; and~~

~~(iii) the price, quantity, duration, and other contract terms directly related to the price, quantity, and duration of the power supply purchase agreement are reasonable.~~

(ii) procurement of the electricity supply resource is consistent with the requirements in 69-3-201, the objectives in 69-8-419, and commission rules.

(d) The commission order may include a provision for allowable generation assets cost of service when the utility has filed an application for the lease or acquisition of an equity interest in a plant or equipment used to generate electricity.

(e) When issuing an order for the acquisition of an equity interest or lease in a facility or equipment that is constructed after January 1, 2007, and that is used to generate electricity that is primarily fueled by natural or synthetic gas, the commission shall require the applicant to implement cost-effective carbon offsets. Expenditures required for cost-effective carbon offsets pursuant to this subsection (6)(e) are fully recoverable in rates. By March 31, 2008, the commission shall adopt rules for the implementation of this subsection (6)(e).

~~(d)~~(f) The commission order may include other findings that the commission determines are necessary.

~~(e)~~(g) A commission order that denies ~~advanced approval~~ approval must describe why the findings required in subsection ~~(3)(c)~~ (6)(c) could not be reached.

~~(4)~~(7) Notwithstanding any provision of this chapter to the contrary, if the commission has issued an order containing the findings required under subsection ~~(3)(c)~~ (6)(c), the commission may not subsequently disallow the recovery of costs ~~incurred under the agreement~~ related to the approved electricity supply resource based on contrary findings.

~~(5) If a default supplier does not apply for advanced approval of a power supply purchase agreement, the commission shall consider the prudence of the default supplier's resource procurement actions in the context of a default supplier's cost recovery filing pursuant to 69-8-210 or in a separate proceeding. The commission's decisions in these proceedings must be based on facts that were known or should reasonably have been known by the default supplier at the time of its procurement decisions.~~

(8) Until the state or federal government has adopted uniformly applicable statewide standards for the capture and sequestration of carbon dioxide, the commission may not approve an application for the acquisition of an equity interest or lease in a facility or equipment used to generate electricity that is primarily fueled by coal and that is constructed after January 1, 2007, unless the facility or equipment captures and sequesters a minimum of 50% of the carbon dioxide produced by the facility. Carbon dioxide captured by a facility or equipment may be sequestered offsite from the facility or equipment.

~~(6)~~(9) Nothing limits the commission's ability to subsequently, in any future ~~cost recovery~~ rate proceeding, inquire into the manner in which the ~~default supplier~~ public utility has managed, dispatched, operated, or maintained any resource or managed any power supply purchase agreement ~~a power supply purchase agreement~~ as part of its overall resource portfolio. The commission may subsequently disallow ~~default supply~~ rate recovery for the costs that result from the failure of a ~~default supplier~~ public utility to reasonably ~~administer power supply purchase agreements~~ manage, dispatch, operate, maintain, or administer electricity supply resources in ~~the context of its overall default supply portfolio management and service obligations.~~ a manner

consistent with 69-3-201, 69-8-419, and commission rules.

~~(7)~~(10) The commission may engage independent engineering, financial, and management consultants or advisory services to evaluate a public utility's ~~default~~ electricity supply resource procurement plans and proposed ~~power supply purchase agreements~~ electricity supply resources. The consultants must have demonstrated knowledge and experience with electricity supply procurement and resource portfolio management, modeling, ~~and~~ risk management, and engineering practices. The commission shall charge a fee to the ~~default supplier~~ public utility to pay for the costs of consultants or advisory services. These costs are recoverable in ~~default supply~~ rates.

(11) By March 31, 2008, the commission shall adopt rules prescribing minimum filing requirements for applications filed pursuant to this part."

Section 16. Section 69-8-602, MCA, is amended to read:

"69-8-602. ~~Distribution services provider~~ Utility net metering requirements. A ~~distribution services provider~~ utility shall:

(1) allow net metering systems to be interconnected using a standard kilowatt-hour meter capable of registering the flow of electricity in two directions, unless the commission determines, after appropriate notice and opportunity for comment:

(a) that the use of additional metering equipment to monitor the flow of electricity in each direction is necessary and appropriate for the interconnection of net metering systems, after taking into account the benefits and costs of purchasing and installing additional metering equipment; and

(b) how the costs of net metering are to be allocated between the customer-generator and the ~~distribution services provider~~ utility; and

(2) charge the customer-generator a minimum monthly fee that is the same as other customers of the electric utility in the same rate class. The commission shall determine, after appropriate notice and opportunity for comment if:

(a) the ~~distribution services provider~~ utility will incur direct costs associated with interconnecting or administering net metering systems that exceed any offsetting benefits associated with these net metering systems; and

(b) public policy is best served by imposing these costs on the customer-generator, rather than allocating these costs among the ~~distribution services provider's~~ utility's entire customer base."

Section 17. Section 69-8-603, MCA, is amended to read:

"69-8-603. Net energy measurement calculation. Consistent with the other provisions of this part, the net energy measurement must be calculated in the following manner:

(1) The ~~distribution services provider~~ utility shall measure the net electricity produced or consumed during the billing period, in accordance with normal metering practices.

(2) If the electricity supplied by the electricity supplier exceeds the electricity generated by the customer-generator and fed back to the electricity supplier during the billing period, the customer-generator must be billed for the net electricity supplied by the electricity supplier, in accordance with normal metering practices.

(3) If electricity generated by the customer-generator exceeds the electricity supplied by the electricity supplier, the customer-generator must be:

(a) billed for the appropriate customer charges for that billing period, in accordance with 69-8-602; and

(b) credited for the excess kilowatt hours generated during the billing period, with this kilowatt-hour credit appearing on the bill for the following billing period.

(4) On January 1, April 1, July 1, or October 1 of each year, as designated by the customer-generator as the beginning date of a 12-month billing period, any remaining unused kilowatt-hour credit accumulated during the previous 12 months must be granted to the electricity supplier, without any compensation to the customer-generator."

Section 18. Section 69-8-1004, MCA, is amended to read:

"69-8-1004. Renewable resource standard -- administrative penalty -- waiver. (1) Except as provided in 69-8-1007 and subsection (11) of this section, a graduated renewable energy standard is established for public utilities as provided in subsections (2) through (4) of this section.

(2) In each compliance year beginning January 1, 2008, through December 31, 2009, each public utility shall procure a minimum of 5% of its retail sales of electrical energy in Montana from eligible renewable resources.

(3) (a) In each compliance year beginning January 1, 2010, through December 31, 2014, each public utility shall procure a minimum of 10% of its retail sales of electrical energy in Montana from eligible renewable resources.

(b) As part of their compliance with subsection (3)(a), public utilities shall purchase both the renewable energy credits and the electricity output from community renewable energy projects that total at least 50 megawatts in nameplate capacity.

(c) Public utilities shall proportionately allocate the purchase required under subsection (3)(b) based on each public utility's retail sales of electrical energy in Montana in the calendar year 2009.

(4) (a) In the compliance year beginning January 1, 2015, and in each succeeding compliance year, each

public utility shall procure a minimum of 15% of its retail sales of electrical energy in Montana from eligible renewable resources.

(b) (i) As part of their compliance with subsection (4)(a), public utilities shall purchase both the renewable energy credits and the electricity output from community renewable energy projects that total at least 75 megawatts in nameplate capacity.

(ii) In meeting the standard in subsection (4)(b)(i), a public utility may include purchases made under subsection (3)(b).

(c) Public utilities shall proportionately allocate the purchase required under subsection (4)(b) based on each public utility's retail sales of electrical energy in Montana in the calendar year 2014.

(5) (a) In complying with the standards required under subsections (2) through (4), a public utility shall, for any given compliance year, calculate its procurement requirement based on the public utility's previous year's sales of electrical energy to retail customers in Montana.

(b) The standard in subsections (2) through (4) must be calculated on a delivered-energy basis after accounting for any line losses.

(6) A public utility has until 3 months following the end of each compliance year to purchase renewable energy credits for that compliance year.

(7) (a) In order to meet the standard established in subsections (2) through (4), a public utility may only use:

(i) electricity from an eligible renewable resource in which the associated renewable energy credits have not been sold separately;

(ii) renewable energy credits created by an eligible renewable resource purchased separately from the associated electricity; or

(iii) any combination of subsections (7)(a)(i) and (7)(a)(ii).

(b) A public utility may not resell renewable energy credits and count those sold credits against the public utility's obligation to meet the standards established in subsections (2) through (4).

(c) Renewable energy credits sold through a voluntary service such as the one provided for in ~~69-8-210(4)~~ 69-8-210(2) may not be applied against a public utility's obligation to meet the standards established in subsections (2) through (4).

(8) Nothing in this part limits a public utility from exceeding the standards established in subsections (2) through (4).

(9) If a public utility exceeds a standard established in subsections (2) through (4) in any compliance year, the public utility may carry forward the amount by which the standard was exceeded to comply with the standard in either or both of the 2 subsequent compliance years. The carryforward may not be double-counted.

(10) Except as provided in subsection (11), if a public utility is unable to meet the standards established in subsections (2) through (4) in any compliance year, that public utility shall pay an administrative penalty, assessed by the commission, of $10 for each megawatt hour of renewable energy credits that the public utility failed to procure. A public utility may not recover this penalty in electricity rates. Money generated from these penalties must be deposited in the universal low-income energy assistance fund established in 69-8-412(1)(a).

(11) A public utility may petition the commission for a short-term waiver from full compliance with the standards in subsections (2) through (4) and the penalties levied under subsection (10). The petition must demonstrate that the:

(a) public utility has undertaken all reasonable steps to procure renewable energy credits under long-term contract, but full compliance cannot be achieved either because renewable energy credits cannot be procured or for other legitimate reasons that are outside the control of the public utility; or

(b) integration of additional eligible renewable resources into the electrical grid will clearly and demonstrably jeopardize the reliability of the electrical system and that the public utility has undertaken all reasonable steps to mitigate the reliability concerns."

Section 19. Use of generation assets. Generation assets acquired by a public utility pursuant to this chapter:

(1) must be used by the public utility to serve and benefit customers within the public utility's Montana service territory; and

(2) may not be removed from the rate base unless the commission finds that customers of the public utility will not be adversely affected.

Section 20. Codification instruction. [Section 19] is intended to be codified as an integral part of Title 69, chapter 8, part 4, and the provisions of Title 69, chapter 8, part 4, apply to [section 19].

Section 21. Repealer. Sections 69-8-102, 69-8-104, 69-8-202, 69-8-203, 69-8-204, 69-8-208, 69-8-209, 69-8-211, 69-8-301, 69-8-302, 69-8-303, 69-8-304, 69-8-308, 69-8-309, 69-8-310, 69-8-404, 69-8-408, 69-8-409, and 69-8-410, MCA, are repealed.

Section 22. Saving clause. [This act] does not affect rights and duties that matured, penalties that were incurred, or proceedings that were begun before [the effective date of this act].

Section 23. Severability. If a part of [this act] is invalid, all valid parts that are severable from the invalid part remain in effect. If a part of [this act] is invalid in one or more of its applications, the part remains in effect in all valid applications that are severable from the invalid applications.

- END -

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